COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Investigation of Kentucky Power Company Rockport Deferral Mechanism	))	Case No. 2022-00283

DIRECT TESTIMONY OF

BRIAN K. WEST

ON BEHALF OF KENTUCKY POWER COMPANY

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BKW-Exhibit 2	Rockport Deferral Regulatory Asset
BKW-Exhibit 3	Rockport Fixed Cost Savings
BKW-Exhibit 4	Estimated Rockport Offset Calculation
BKW-Exhibit 5	RRA State Regulatory Evaluations – Energy

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Brian K. West. My position is Vice President, Regulatory & Finance for Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1645 Winchester Avenue, Ashland, Kentucky 41101.

II. BACKGROUND

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received an Associate's degree in Applied Science (Electronics Technology) and a Bachelor's degree in Business Management, both from Ohio University, in 1987 and 1988, respectively. I obtained a Master of Business Administration degree from Ohio Dominican University in 2008.

I began my utility industry career when I joined Ohio Power Company as a customer services assistant in Portsmouth, Ohio in 1989. This was a supervisor-in-training position, where I worked in each area of the office (*e.g.,* cashiering, new service, and credit and collections) to gain knowledge and experience with every aspect of managing an area office. After completing the training program, I initially supervised meter readers in the Portsmouth office until being promoted to office supervisor in 1993. In 1997, when the area offices closed, I transferred to Chillicothe, Ohio and accepted the position of customer services field supervisor, with responsibility for managing customer field representatives who primarily worked with customers on high-bill and other inquiries.

In 2000, after American Electric Power Company ("AEP") merged with Central and South West Corporation, I moved to Columbus, Ohio, where I held various positions in Customer Operations, mostly in process improvement and supporting regulatory filings. In 2008, I transferred to AEP's Regulatory Services department, where I supported various filings before public service commissions in Arkansas, Indiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia, as well as the Public Service Commission of Kentucky ("Commission").

In 2010, I was promoted to regulatory case manager, with responsibility for energy efficiency/demand response filings, integrated resource plan filings, and various renewable filings across AEP's service territory. In 2016, I moved to a case manager role with primary responsibility for most Appalachian Power Company filings before the Public Service Commission of West Virginia, the Virginia State Corporation Commission, and the Tennessee Public Utility Commission. I accepted the position of Director of Regulatory Services for Kentucky Power in February 2019. I assumed my current position as Vice President, Regulatory & Finance for Kentucky Power Company in January 2021.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT, REGULATORY & FINANCE FOR KENTUCKY POWER?

A. I am primarily responsible for managing the regulatory and financial strategy for Kentucky Power. This includes planning and executing rate filings for both federal and state regulatory agencies, as well as filings for certificates of public convenience and necessity before this Commission. I am also responsible for managing the Company's financial operating plans. Included as part of this responsibility is the preparation and coordination of various capital and operation and maintenance ("O&M") budgets to ensure that adequate resources such as debt, equity, and cash are available to build, operate, and maintain Kentucky Power's electric system assets used to provide service to the Company's retail and wholesale customers.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have filed testimony in support of Kentucky Power's regulatory filings since 2019. Most germane to my testimony in this case, I filed testimony in Case No. 2020-00174, the Company's most recent base rate case proceeding.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am testifying in support of the implementation of the Rockport UPA Expense Deferral provisions of the settlement agreement ("2017 Settlement Agreement"), approved by the Commission in Case No. 2017-00179, the Company's 2017 base rate proceeding. In the 2017 Settlement Agreement, Kentucky Power agreed to defer for customers' benefit a total of $50 million in non-fuel, non-environmental Rockport UPA expense for recovery beginning December 9, 2022. The 2017 Settlement Agreement is included as **BKW-Exhibit 1**.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the following exhibits:

BKW-Exhibit 1: 2017 Settlement Agreement in Case No. 2017-00179

BKW-Exhibit 2: Rockport Deferral Regulatory Asset

BKW-Exhibit 3: Rockport Fixed Cost Savings

BKW-Exhibit 4: Estimated Rockport Offset Calculation

BKW-Exhibit 5: RRA State Regulatory Evaluations – Energy

IV. 2017 SETTLEMENT AGREEMENT

Q. BEFORE ADDRESSING THE PARTICULARS OF THE ROCKPORT UPA DEFERRAL PROVISIONS APPROVED BY THE COMMISSION, PLEASE EXPLAIN THE UNDERLYING BASIS FOR THE ROCKPORT DEFERRAL.

A. Kentucky Power is a party to a FERC-approved unit power agreement ("Rockport UPA") under which it is entitled to 15 percent of the capacity and energy associated with Rockport Unit 1 and Rockport Unit 2. The Rockport UPA is scheduled to expire on December 8, 2022. The total annual Rockport UPA non-fuel, non-environmental expense currently in customer rates is approximately $50.8 million. Approximately $40.8 million of this amount is in base rates ("Rockport Fixed Cost Savings"), and the remaining approximately $10 million is in Tariff P.P.A. The possibility of this $50.8 million annual reduction in expenses following the expiration of the Rockport UPA allowed the parties to the 2017 Settlement Agreement to: (a) defer through the creation of a regulatory asset $50 million in Rockport UPA expenses the Company otherwise would have been entitled to collect during the period January 18, 2018 through December 8, 2022; and (b) immediately flow back to customers beginning December 9, 2022 a portion of the Rockport UPA expense savings without the necessity of a base rate case.

In return for the very significant benefits the Company will have provided for nearly five years, Kentucky Power is entitled to use a portion of the Rockport UPA expense savings to credit that portion of the Rockport Fixed Cost Savings required to permit the Company to earn on a per-books basis its Commission-authorized return on equity ("ROE") for 2023 only, and to begin to amortize the Rockport Deferral Regulatory Asset beginning December 9, 2022.

Q. PLEASE PROVIDE A SUMMARY OF THE KEY ASPECTS OF THE 2017 SETTLEMENT AGREEMENT.

A. The 2017 Settlement Agreement has three key features:

(1) Beginning December 9, 2022 the Company will begin amortizing the $50 million Rockport Deferral Regulatory Asset (plus accumulated weighted average cost of capital ("WACC") carrying charge) approved by the Commission in its January 18, 2018 Order in Case No. 2017-00179. The agreement provides for a five-year amortization period; this five-year period matches the five-year deferral period. The amortization expense will be recovered through the Company's Tariff P.P.A. (Purchase Power Adjustment);

(2) Because the Company has elected not to extend the Rockport UPA, the Company will be entitled to credit that portion of the Rockport Fixed Cost Savings required to permit the Company to earn on a per-books basis its Commission-authorized return on equity ("ROE") for 2023 only ("Rockport Offset"). The Company will recover the Rockport Offset through its Tariff P.P.A.; and

(3) The Company will credit to customers through Tariff P.P.A. the balance of the Rockport Fixed Cost Savings.

Q. WHAT IS THE COMPANY'S CURRENT AUTHORIZED ROE?

A. Kentucky Power's current authorized ROE is 9.3% as approved by the Commission in Case No. 2020-00174.

Q. DID THE COMPANY EXTEND THE ROCKPORT UPA?

A. No. Kentucky Power notified the Commission, as part of its application filed February 8, 2021 in Case No. 2021-00004[1], that it would not extend the Rockport UPA.[2]

Q. CAN YOU QUANTIFY THE AMOUNT OF THE ROCKPORT DEFERRAL REGULATORY ASSET?

A. Yes. The amount of the Rockport Deferral Regulatory Asset at the time of the expiration of the Rockport UPA, on December 8, 2022, is estimated to be $58.1 million. See **BKW-Exhibit 2** for a detailed calculation of the Rockport Deferral Regulatory Asset.

Q. WHAT IS THE AMOUNT OF NON-FUEL, NON-ENVIRONMENTAL ROCKPORT EXPENSE CURRENTLY IN CUSTOMER RATES?

A. The annual amount of Rockport non-fuel, non-environmental (not recovered through the Environmental Surcharge) expense in the Company's base rates and Tariff P.P.A. are approximately $50.8 million.

Q. WHAT PORTION OF THAT AMOUNT IS IN BASE RATES?

A. The net annual amount in the Company's base rates ("Rockport Fixed Cost Savings") is approximately $40.8 million ($50.8 million - $10 million base rate credit collected through

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[1] Application, *In the Matter of: Electronic Application Of Kentucky Power Company For Approval Of A Certificate Of Public Convenience And Necessity For Environmental Project Construction At The Mitchell Generating Station, An Amended Environmental Compliance Plan, And Revised Environmental Surcharge Tariff Sheets*, Case No. 2021-00004 at 3 (Feb. 8, 2021).

[2] *See also id.,* Kentucky Power's response to Commission Staff's First Set of Data Requests, Item 5 (Mar. 26, 2021).

Tariff P.P.A.). Please see **BKW-Exhibit 3**[3] for a detailed accounting of the Rockport Fixed Cost Savings.

Q. WHAT TYPES OF EXPENSES ARE INCLUDED IN THE ROCKPORT FIXED COST SAVINGS?

A. The Rockport Fixed Cost Savings included in the Company's base rates includes all of the non-fuel operating expenses including depreciation and taxes, as well as the formulaic return on invested capital included in the Rockport UPA.

Q. PLEASE EXPLAIN HOW THE ROCKPORT OFFSET WILL WORK.

A. The 2017 Settlement Agreement requires the Company to file by November 15, 2022, updated rates for Tariff P.P.A. to reflect the Rockport Fixed Cost Savings (credit), the Estimated Rockport Offset (debit) and the Rockport Deferral Regulatory Asset (debit). Since the approximate amounts of the Rockport Fixed Cost Savings and Rockport Deferral Regulatory Asset are known, and Kentucky Power's actual 2023 ROE cannot be known until early in 2024, the amount of the Rockport Offset must be estimated and then trued-up to the actual amount when that amount is known.

Q. CAN THE ROCKPORT OFFSET EXCEED THE ROCKPORT FIXED COST SAVINGS?

A. No.

Q. HOW WILL THE ESTIMATED ROCKPORT OFFSET BE CALCULATED?

A. The amount of the Estimated Rockport Offset will be calculated based on a per-books 12-month ending June 30, 2022 ROE. The Rockport Offset calculation template was included

[3] Provided in Case No. 2021-00481 in the Company's response to the Attorney General's Second Set of Data Requests, Item 24.

as an exhibit to the 2017 Settlement Agreement and the Estimated Rockport Offset calculation is included as **BKW-Exhibit 4**.

Q. WHEN WILL THE ROCKPORT OFFSET TRUE-UP TAKE PLACE?

A. On or before February 1, 2024, the Company will file an updated Tariff P.P.A. rate to be effective March 1, 2024, which will include the Rockport Offset true-up to be recovered over a three-month period.

Q. WHAT IS THE AMORTIZATION PERIOD FOR THE ROCKPORT DEFERRAL REGULATORY ASSET?

A. The amortization period for the Rockport Deferral Regulatory Asset, per the Commission-approved 2017 Settlement Agreement, is five years beginning December 9, 2022.

Q. DURING THE AMORTIZATION PERIOD, WHAT CARRYING CHARGE WILL BE USED?

A. Per the 2017 Settlement Agreement, the Rockport Deferral Regulatory Asset will be subject to carrying charges for the entirety of the amortization period first based on a WACC of 7.62%[4], as approved in the Company's 2020 base rate proceeding, Case No. 2020-00174. The Commission-approved WACC in future base rate proceedings will be used for the duration of the amortization period for the Rockport Deferral Regulatory Asset.

Q. DOES THE COMPANY HAVE AN ESTIMATE OF THE ROCKPORT SAVINGS TO BE RETURNED TO CUSTOMERS IN 2023?

A. Yes. The Company estimates $14.4 million will be returned to customers through reduced rates during 2023. Of the $50.8 million in savings (**BKW-Exhibit 3**), $13.6 million of the

[4] Case No. 2020-00174, Order Appendix A, Page 3 of 3 (Jan. 13, 2021).

balance will be allocated to payment of the Rockport Deferral Regulatory Asset (**BKW-Exhibit 2**); the remaining $22.8 million will be required for the Estimated Rockport Offset in 2023 (**BKW-Exhibit 4**).

V. ESTABLISHING THE MANNER AND TIMING OF COST RECOVERY

Q. WHAT DID THE COMMISSION FIND IN ITS JANUARY 13, 2021 ORDER IN CASE NO. 2020-00174 WITH REGARD TO THE COMPANY'S REQUEST TO AMORTIZE THE ROCKPORT DEFERRAL REGULATORY ASSET OVER FIVE YEARS BEGINNING IN DECEMBER 2022?

A. The Commission declined at that time the Company's request to begin a five-year amortization period beginning in December 2022.[5] Further, the Commission stated that it would "…also review and clarify items related to provisions of the final Order in Case No. 2017-00179 regarding Kentucky Power's ability to use the savings from the expiration of the Rockport UPA to earn its Commission-approved ROE in calendar year 2023."[6]

Q. IS THE 2017 SETTLEMENT AGREEMENT APPROVED BY THE COMMISSION CLEAR REGARDING THE ROCKPORT OFFSET?

A. Yes. The 2017 Settlement Agreement is clear, and it states: "However, for 2023 only, the Rockport Fixed Cost Savings credit will be offset by the amount, if any, necessary for the Company to earn its Kentucky Commission-authorized return on equity (ROE) for 2023 ('Rockport Offset')."[7]

Moreover, the 2017 Settlement Agreement goes on to define the Actual Rockport Offset.

[5] Case No. 2020-00174, Order at 65 (Jan. 13, 2021).
[6] *Id.* at page 65.
[7] 2017 Settlement Agreement at page 6.

> "Actual Rockport Offset" shall mean the amount of additional annual revenue that would have been necessary for the Company to earn the Commission-authorized return on equity for 2023 considering the termination of the Rockport UPA and the Rockport Fixed Cost Savings. The Company shall calculate the Actual Rockport Offset using a comparison of the per books return on equity for 2023 to the Commission-approved return on equity. The Actual Rockport Offset cannot exceed the Rockport Fixed Costs Savings.

Q. GIVEN THAT THE AMORTIZATION PERIOD FOR THE ROCKPORT DEFERRAL REGULATORY ASSET IS FIVE YEARS BEGINNING DECEMBER 9, 2022, PER THE 2017 SETTLEMENT AGREEMENT, WHAT DOES THE COMMISSION NEED TO DO IN THIS CASE?

A. In the January 18, 2018 Order in Case No. 2017-00179, the Commission stated, "…this approval is for accounting purposes only, and the appropriate ratemaking treatment for the regulatory asset account will be addressed in Kentucky Power's next general rate case." In the Company's subsequent general rate case, 2020-00174, the Commission deferred a decision regarding ratemaking treatment to a future proceeding. In its September 2, 2022 Order initiating this proceeding, the Commission confirmed that it will address the amortization and recovery of the Rockport Deferral Regulatory Asset in this proceeding. The Commission therefore needs to: 1) approve the amortization of the Rockport Deferral Regulatory Asset over 5 years through Tariff P.P.A beginning December 9, 2022, consistent with the settlement agreement modified and approved in Case No. 2017-00179; 2) review and approve the Rockport Fixed Cost Savings; and 3) review and approve the methodology for estimating the Rockport Offset amount to be used in Tariff P.P.A. until the Rockport Offset true-up takes place.

Q. IF THE COMMISSION WERE TO MODIFY IN SOME WAY THE TERMS OF THE 2017 SETTLEMENT AGREEMENT, WHAT EFFECT MIGHT THAT HAVE ON KENTUCKY POWER?

A. As mentioned in the Company's August 12, 2022 filing, the damage associated with such a modification could be far reaching. First , altering the terms of a Commission-approved settlement agreement, especially in the instant case when cost recovery is about to commence, sends a message to financial institutions, the market, and to potential investment in the Commonwealth that Commission-approved settlement agreements cannot be reasonably relied upon. Orders and settlement agreements are used by the Company and other Kentucky utilities for financial forecasts and planning, while financial institutions and rating agencies use them to determine the level of risk associated with operating in the given regulatory environment. Rating agency downgrades are possible which in turn will increase risk of borrowing raising interest rates which will ultimately be passed on to customers. When the Company's customers have received the full benefit of the 2017 Settlement Agreement for nearly five years, it is only fair that the Company should receive the consideration approved by the Commission in exchange for its five-year commitment to accept lower rates in the near term.

Q. ARE FINANCIAL INSTITUTIONS THAT LEND TO KENTUCKY POWER AWARE OF THIS RISK?

A. Yes, I believe they would be. In the May 30, 2022 edition of Regulatory Research Associates, a group within S&P Global Commodity Insights, entitled "RRA State Regulatory Evaluations – Energy," included as **BKW-Exhibit 5**, the report stated, "The team lowered the ranking of Kentucky regulation to Average/2 from Average/1 to account for the Kentucky Public Service Commission's pattern of modifying or rejecting rate case settlements over the preceding months." This indicates to financial institutions and investors an increased risk of doing business in the Commonwealth. Any retroactive revision of the approved settlement agreement would only confirm this risk.

VI. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets Or Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

SETTLEMENT AGREEMENT

This Settlement Agreement, made and entered into this 22nd day of November, 2017, by and among Kentucky Power Company ("Kentucky Power" or "Company"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky School Boards Association ("KSBA"); Kentucky League of Cities ("KLC"); Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"); and Kentucky Cable Telecommunications Association ("KCTA"); (collectively Kentucky Power, KIUC, KSBA, KLC, Wal-Mart, and KCTA, are "Signatory Parties").

RECITALS

1. On June 28, 2017 Kentucky Power filed an application pursuant to KRS 278.190, KRS 278.183, and the rules and regulations of the Public Service Commission of Kentucky ("Commission"), seeking an annual increase in retail electric rates and charges totaling $69,575,934, seeking approval of its 2017 Environmental Compliance Plan, an order approving accounting practices to establish regulatory assets or liabilities, and further seeking authority to implement or amend certain tariffs ("June 2017 Application").

2. On August 8, 2017, Kentucky Power supplemented its filing to reflect the impact of subsequent refinancing activities on the Company's Application ("August 2017 Refinancing Update"). The refinancing activities reduced the Company's requested annual increase in retail electric rates and charges from $69,575,934 to $60,397,438.

3. KIUC, KSBA, KLC, Wal-Mart, and KCTA filed motions for full intervention in Case No. 2017-00179. The Commission granted the intervention motions. Collectively KIUC, KSBA, KLC, Wal-Mart, and KCTA are referred to in this Settlement Agreement as the "Settling Intervenors."

4. The Attorney General of the Commonwealth of Kentucky ("Attorney General") and Kentucky Commercial Utility Customers, Inc. ("KCUC") also filed motions to intervene. The Attorney General and KCUC, who are not parties to this agreement, were granted leave to intervene.

5. Certain of the Settling Intervenors, KCUC, and the Attorney General filed written testimony in Case No. 2017-00179 raising issues regarding Kentucky Power's Rate Application.

6. Kentucky Power, KCUC, the Attorney General, and the Settling Intervenors have had a full opportunity for discovery, including the filing of written data requests and responses.

7. Kentucky Power offered the Settling Intervenors, KCUC, and the Attorney General, along with Commission Staff, the opportunity to meet and review the issues presented by Kentucky Power's application in this proceeding and for purposes of settlement.

8. The Signatory Parties execute this Settlement Agreement for purposes of submitting it to the Kentucky Public Service Commission for approval pursuant to KRS 278.190 and KRS 278.183 and for further approval by the Commission of the rate increase, rate structure, and tariffs as described herein.

9. The Signatory Parties believe that this Settlement Agreement provides for fair, just, and reasonable rates.

NOW, THEREFORE, for and in consideration of the mutual promises set forth above, and the agreements and covenants set forth herein, Kentucky Power and the Settling Intervenors hereby agree as follows:

AGREEMENT

1. Kentucky Power's Application

(a) Except as modified in this Settlement Agreement, Kentucky Power's June 2017 Application as updated by the August 2017 Refinancing Update is approved.

2. Revenue Requirement

(a) Effective for service rendered on or after January 19, 2018, Kentucky Power shall implement a base rate adjustment sufficient to generate additional annual retail revenues of $31,780,734. This annual retail revenue amount represents a $28,616,704 million reduction from the $60,397,438 sought in the Company's August 2017 Refinancing Update.

(b) The $28,616,704 million reduction was the result of the following adjustments to the Company's request in the June 2017 Rate Application as modified in the August 2017 Refinancing Update:

Adjustment	Reduction in Revenue Requirement ($Millions)
Defer a portion of Rockport UPA non-fuel, non-environmental expenses	15.0
Increase revenues to Apply Weather Normalization to Commercial Sales Net of Variable O&M	0.40
Reduce Incentive Compensation	3.15
Reduce Amortization Expense to Recalibrate Storm Damage Amortization	1.22

Reduce Depreciation Expense by Extending Service Life of BS1 to 20 years	2.84
Reduce Depreciation Expense by Removing Terminal Net Salvage for BSU1	0.37
Reduce Depreciation Expense by Removing Terminal Net Salvage for Mitchell	0.57
Increase Short Term Debt to 1% and Set Debt Rate at 1.25%	0.36
Change in Return on Equity from 10.31% to 9.75%	4.70
Total Adjustments	**28.6**

(c) Kentucky Power agrees to allocate the $31,780,734 in additional annual revenue as illustrated on **Exhibit 1.** The Company will design rates and tariffs consistent with this allocation of additional revenue.

(i) As part of the Commission's consideration of the reasonableness of this Settlement Agreement, the tariffs designed in accordance with this subparagraph shall be filed with the Commission and served on counsel for all parties to this case no later than December 1, 2017.

(ii) Within ten days of the entry of the Commission's Order approving without modification this Settlement Agreement and the rates thereunder, Kentucky Power shall file with the Commission signed copies of the tariffs in conformity with 807 KAR 5:011.

3. Rockport UPA Expense Deferral

(a) Kentucky Power is a party to a FERC-approved Unit Power Agreement with AEP Generating Company for capacity and energy produced at the Rockport Plant ("Rockport UPA"). The Rockport UPA expires on December 8, 2022.

(b) Kentucky Power will defer a total of $50 million in non-fuel, non-environmental Rockport UPA Expense for later recovery as follows:

(i) Kentucky Power will defer $15M annually of Rockport UPA Expense in 2018 and 2019 for later recovery.

(ii) Kentucky Power will defer $10M of Rockport UPA Expense in 2020 for later recovery.

(iii) Kentucky Power will defer $5M annually of Rockport UPA Expense in years 2021 and 2022 for later recovery.

(c) The Rockport UPA Expense of $50 million described in Paragraph 3(b) above will be deferred into a regulatory asset ("the Rockport Deferral Regulatory Asset") and will be subject to carrying charges based on a weighted average cost of capital ("WACC") of 9.11%[1] until the Regulatory Asset is fully recovered. From January 1, 2018 through December 8, 2022, the WACC will be applied to the monthly Rockport Deferral Regulatory Asset principal balance net of accumulated deferred income taxes ("ADIT"). From December 9, 2022 until the Rockport Deferral Regulatory Asset is fully recovered, the WACC will be applied to the monthly Rockport Deferral Regulatory Asset balance including deferred carrying charges net of ADIT. The Rockport Deferral Regulatory Asset shall be recovered on a levelized basis through the demand component of Tariff P.P.A. and amortized over five years beginning on December 9, 2022. Kentucky Power estimates that the regulatory asset balance will total approximately $59 million on December 8, 2022.

(d) Additional expenses reflecting the declining deferral amount in years 2020 through 2022 will be recovered through the demand component of Tariff P.P.A. as follows:

(i) Kentucky Power will recover $5 million through Tariff P.P.A. in 2020

(ii) Kentucky Power will recover $10 million through Tariff P.P.A. in 2021

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[1] 6.48% grossed up for applicable State and Federal taxes, uncollectible accounts expense, and the KPSC maintenance fee

(iii) Kentucky Power will recover $10 million through Tariff P.P.A. in 2022, prorated through December 8, 2022.

(e) The Signatory Parties acknowledge that the Company's decision whether to seek Commission approval to extend the Rockport UPA will be made at a later date. Whether or not the Company seeks to extend the Rockport UPA, beginning December 9, 2022, the Capacity Charge recovered through Tariff C.C., approved in Case No. 2004-00420, will end. Any final over- or under-recovery balance will be included in the subsequent calculation of the purchase power adjustment under Tariff P.P.A. In the event that Kentucky Power elects not to extend the Rockport UPA, it will experience a reduction in Rockport UPA fixed costs ("Rockport Fixed Costs Savings").

(f) If Kentucky Power elects not to extend the Rockport UPA, it will, beginning December 9, 2022, credit the Rockport Fixed Cost Savings through the demand component of Tariff P.P.A. until new base rates are set. However, for 2023 only, the Rockport Fixed Cost Savings credit will be offset by the amount, if any, necessary for the Company to earn its Kentucky Commission-authorized return on equity (ROE) for 2023 ("Rockport Offset"). An example of the calculation of the Rockport Offset is included as **EXHIBIT 2**.

(g) For the purposes of implementing the Rockport Fixed Costs Savings credit described in Paragraph 3(f) above, the following definitions apply:

(i) "Rockport Fixed Costs Savings" shall mean the annual amount of non-fuel, non-environmental Rockport UPA expense included in base rates for rates effective in November 2022.

(ii) "Estimated Rockport Offset" shall mean the amount of additional annual revenue the Company estimates would be necessary for it to earn the Commission-authorized return on equity for 2023 considering the termination of the Rockport UPA and the Rockport Fixed Cost Savings.

(iii) "Actual Rockport Offset" shall mean the amount of additional annual revenue that would have been necessary for the Company to earn the Commission-authorized return on equity for 2023 considering the termination of the Rockport UPA and the Rockport Fixed Cost Savings. The Company shall calculate the Actual Rockport Offset using a comparison of the per books return on equity for 2023 to the Commission-approved return on equity. The Actual Rockport Offset cannot exceed the Rockport Fixed Costs Savings.

(iv) "Rockport Offset True-Up" shall mean the difference between the Estimated Rockport Offset and the Actual Rockport Offset.

(h) The Company shall implement the Rockport Fixed Costs Savings credit described in Paragraph 3(f) above as follows:

(i) By November 15, 2022, the Company shall file an updated purchase power adjustment factor under Tariff P.P.A. for rates effective December 9, 2022. This filing shall reflect the impact of the Rockport Fixed Cost Savings and the Estimated Rockport Offset on the purchase power adjustment factor. This filing shall also reflect the commencement of recovery of the Rockport Deferral Regulatory Asset.

(ii) The Company shall make its normal August 15, 2023 Tariff P.P.A. filing for rates effective in October 2023. The Rockport Fixed Cost Savings and the Estimated Rockport Offset will continue to be factored into the calculation of the purchase power adjustment factor through the end of 2023. Beginning in January 2024, the Estimated Rockport Offset will not be factored into the calculation of the purchase power adjustment factor.

(iii) By February 1, 2024, the Company shall file an updated purchase power adjustment factor under Tariff P.P.A. for rates effective March 1, 2024. This filing shall only reflect the impact of the Rockport Offset True-Up on the purchase power adjustment factor. The purchase power adjustment factor shall be established to recover or credit the Rockport Offset True-Up amount in three months.

(iv) Beginning with the August 15, 2024 Tariff P.P.A. filing, the Company will incorporate the Rockport Fixed Cost Savings in its annual calculation of the purchase power adjustment factor.

4. PJM OATT LSE Expense Recovery

(a) As described in the testimony of Company Witness Vaughan, Kentucky Power has included an adjusted test year amount of net PJM OATT LSE charges and credits in base rates. Kentucky Power will track, on a monthly basis, the amount of OATT LSE charges and credits above or below the base rate level using deferral accounting. Kentucky Power will recover and collect 80% of the annual over or under collection of PJM OATT LSE charges, as compared to the annual amount included in base rates, ("Annual PJM OATT LSE Recovery") through the operation of Tariff P.P.A.

(b) Kentucky Power will credit against the Annual PJM OATT LSE Recovery 100% of the difference between the return on its incremental transmission investments calculated using the FERC-approved PJM OATT return on equity and the return on its incremental transmission investments calculated using the 9.75% return on equity provided for in this settlement (the "Transmission Return Difference"). Kentucky Power shall calculate the Transmission Return Difference as shown in **EXHIBIT 3**.

(c) These changes to Tariff P.P.A. to allow for the Annual PJM OATT LSE Recovery will terminate on the effective date when base rates are reset in the next base rate proceeding unless otherwise specifically extended by the Commission. Nothing in this Paragraph 4(c) prohibits Kentucky Power or any other Signatory Party from taking any position regarding the extension of the Annual PJM OATT LSE Recovery mechanism or any other treatment of the Company's PJM OATT LSE expenses.

5. Rate Case Stay Out

(a) Kentucky Power will not file an application for a general adjustment of base rates for rates that would be effective prior to the first day of the January 2021 billing cycle. This rate case "stay out" is expressly conditioned on Commission approval of this Settlement Agreement without modification including the recovery of the Rockport Deferral Regulatory Asset as described in Section 3 above and the incremental PJM OATT LSE expense through Tariff P.P.A. as described in Section 4 above.

(b) This stay out will not apply if a change in law occurs that will result in a material adverse effect on the Company's financial condition.

(c) Nothing in this stay out provision should be interpreted as prohibiting the Commission from altering the Company's rates upon its own investigation, or upon complaint, including to reflect changes in the tax code, including the federal corporate income tax rate, depreciation provisions, or upon a request by the Company to seek leave to address an emergency that could adversely impact Kentucky Power or its customers. In the event the Commission initiates an investigation or a complaint is filed with the Commission regarding the Company's rates, the Company retains the right to defend the reasonableness of its rates in such proceedings.

6. Tariff P.P.A.

(a) Kentucky Power's proposed changes to Tariff P.P.A., as set forth in the testimony of Company Witness Vaughan and modified by Sections 2 and 3 above, are approved.

(b) A revised version of Tariff P.P.A. incorporating the modifications described in Sections 2 and 3 above is included as **EXHIBIT 4.**

7. Depreciation Rates

(a) Kentucky Power and the Settling Intervenors agree that Big Sandy Unit 1 has an expected life of 20 years following its conversion from a coal-fired to a natural gas-fired generating unit. The depreciation rates for Big Sandy Unit 1 have been adjusted to reflect the 20 year expected life. Kentucky Power and the Signatory Parties retain the right to propose updated depreciation rates for Big Sandy Unit 1 in future proceedings to reflect updates to the expected life.

(b) Kentucky Power has adjusted depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant to remove terminal net salvage costs. Kentucky Power retains the right to propose updated depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant in future proceedings to include terminal net salvage costs, and the Settling Intervenors retain the right to challenge the inclusion of such costs in future proceedings.

(c) Kentucky Power's updated depreciation rates are included as **EXHIBIT 5**.

8. Return on Equity, Capitalization, WACC, and GRCF

(a) Kentucky Power shall be authorized a 9.75% return on equity. The authorized return on equity of 9.75% will be used in the calculation of the Company's Environmental Surcharge factor (for non-Rockport environmental projects) and the carrying charges for the Rockport Deferral and Decommissioning Rider regulatory assets.

(b) Kentucky Power will update its capitalization to reflect short term debt as 1% of the Company's total capital structure. The annual interest rate for the short term debt will be set at 1.25%.

(c) Kentucky Power shall utilize a weighted average cost of capital ("WACC") of 9.11% including a gross revenue conversion factor ("GRCF") of 1.6433%. The GRCF does not include a Section 199 deduction. This WACC and GRCF shall remain constant (including for the riders and surcharges described in Paragraph 8(a) above) until such time as the Commission sets base rates in the Company's next base rate case proceeding. The calculations of the WACC and GRCF are shown on **Exhibit 6**.

9. Storm Damage Expense Amortization

(a) Kentucky Power will recover and amortize the remaining unamortized balance of its deferred storm expense regulatory asset authorized in Case No. 2012-00445 over a period of five years beginning January 1, 2018, consistent with the recommendation of KIUC. The unamortized balance of the regulatory asset authorized in Case No. 2012-00445 will total $6,087,000 on December 31, 2017 and will be amortized over five years at an annual amount of $1,217,400.

(b) Kentucky Power will recover and amortize the deferred storm expense regulatory asset authorized in Case No. 2016-00180 over a period of 5 years beginning January 1, 2018 consistent with the testimony of Company Witness Wohnhas. The balance of the regulatory asset authorized in Case No. 2016-00180 totals $4,377,336 and will be amortized over five years at an annual amount of $875,467.

(c) The combined balance of the Kentucky Power's deferred storm expense regulatory assets (the remaining unamortized balance authorized in Case No. 2012-00445 and the amount authorized in Case No. 2016-00180) will total $10,464,336 on December 31, 2017 and will be amortized over five years at an annual amount of $2,092,867.

10. Kentucky Economic Development Surcharge

(a) Kentucky Power's new Kentucky Economic Development Surcharge Tariff ("Tariff K.E.D.S.") shall be approved with rates amended as follows:

(i) The KEDS rate for residential customers will be set at $0.10 per meter instead of $0.25 as proposed by the Company.

(ii) The KEDS rate for non-residential customers for which the KEDS applies will be set at $1.00 per meter instead of $0.25 as proposed by the Company.

(b) All KEDS funds collected by Kentucky Power shall be matched dollar-for-dollar by Kentucky Power from shareholder funds. The proceeds of KEDS and Kentucky Power's shareholder contribution shall be used by Kentucky Power for economic development projects, including the training of local economic development officials, in the Company's service territory. The KEDS, and the matching shareholder contribution, shall remain in effect until changed by order of the Commission.

(c) Kentucky Power will continue to file on or before March 31st of each year a report with the Commission describing: (i) the amount collected through the Economic Development Surcharge; and (ii) the matching amount contributed by Kentucky Power from shareholder funds. The annual report to be filed by the Company shall also describe the amount, recipients, and purposes of its expenditure of the funds collected through the Economic Development Surcharge and shareholder contribution.

(d) Kentucky Power shall serve a copy of the annual report to be filed with the Commission in accordance with subparagraph (c) on counsel for all parties to this proceeding.

11. Backup and Maintenance Service

(a) In order for Marathon Petroleum LP ("Marathon") to evaluate the economics of self or co-generation, Kentucky Power and Marathon will begin negotiations regarding the terms, conditions and pricing for backup and maintenance service within 30 days of a Commission Order approving this provision and will complete negotiations within the next 120 days. Prior to the start of the 120 day negotiation period, Marathon will provide Kentucky Power with specific information regarding the MW size of a potential self or co-generation facility and the type of generation technology being considered.

(b) If Kentucky Power and Marathon cannot reach an agreement on backup and maintenance service within 120 days, Kentucky Power and Marathon agree to submit the issue to the Commission for resolution.

12. School Energy Manager Program

(a) Kentucky Power shall seek leave from the Commission to include up to $200,000 for the School Energy Manager Program in its each of its 2018 and 2019 DSM Program offerings.

(b) Kentucky Power and KSBA both expressly acknowledge that there is in Case No. 2017-00097 a currently-pending Commission investigation of the Company's DSM programs and funding and that the outcome of that investigation could impact the School Energy Manager Program.

13. Tariff K-12 School

(a) Kentucky Power shall continue its current Pilot Tariff K-12 School but shall remove the Pilot designation as set forth in **Exhibit 7**. Tariff K-12 School shall be available for general service to all K-12 schools in the Company's service territory, public and private, with normal maximum demands greater than 100 kW. Tariff K-12 School shall reflect rates for customers taking service under the tariff designed to produce annually in the aggregate $500,000 less from Tariff K-12 School customers than would be produced under the new L.G.S. rates to be established under this Settlement Agreement from customers eligible to take service under Tariff K-12 School. The aggregate total revenues to be produced by Tariff K-12 School and Tariff L.G.S. shall be equal to the revenues that would be produced in the aggregate by the new rates in the absence of Tariff K-12 School. Service under Tariff K-12 School shall be optional.

14. Bill Format Changes

(a) The bill formatting changes proposed by the Company in Case No. 2017-00231 and consolidated into this case by Commission Order dated July 17, 2017, to the extent not already approved, are approved.

(b) Within 180 days of a Commission Order approving this Settlement, Kentucky Power will conduct a training session with representatives from its municipal clients and KLC to explain the new bill format and tools available to clients to evaluate their electric usage.

15. Renewable Power Option Rider

(a) The proposed changes to the Company's Green Pricing Option Rider, including renaming the rider to the Renewable Power Option Rider ("Rider R.P.O."), are approved except that the availability of service provision for Option B will state the following:

> "Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. tariffs, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1000 kW of peak demand."

A revised version of Rider R.P.O. incorporating the modifications described above is included as **EXHIBIT 8**. Bills for customers receiving service under Rider R.P.O. will include a separate line item for Rider R.P.O. charges.

(b) Beginning no later than March 31, 2018, and no later than each March 31 thereafter, Kentucky Power will file a report with the Commission describing the previous year's activity under Rider R.P.O. This annual report will replace the semi-annual reports filed in Case No. 2008-00151.

16. Modifications To Kentucky Power's Rate Tariffs

In addition to the rate and tariff changes described and agreed to above, Kentucky Power and the Settling Intervenors agree that the following tariffs shall be modified or implemented as described below:

(a) The Customer charge for the Residential Class ("Tariff R.S.") shall be increased to $14.00 per month instead of the $17.50 per month proposed by the Company in its filing in this case.

(b) The Company is extending the termination date for Tariff C.S. – Coal and the amendments to Tariff C.S. – I.R.P. and Tariff E.D.R. approved in Case No. 2017-00099 from December 31, 2017 to December 31, 2018.

(c) The pole attachment rate under Tariff C.A.T.V. shall be $10.82 for attachments on two-user poles and $6.71 for attachments on three-user poles for all attachments instead of the $11.97 for attachments on two-user poles and $7.42 for attachments on three-user poles proposed by the Company in its filing in this case.

17. Filing Of Settlement Agreement With The Commission And Request For Approval

Following the execution of this Settlement Agreement, Kentucky Power and the Settling Intervenors shall file this Settlement Agreement with the Commission along with a joint request to the Commission for consideration and approval of this Settlement Agreement so that Kentucky

Power may begin billing under the approved adjusted rates for service rendered on or before January 19, 2018.

18. Good Faith And Best Efforts To Seek Approval

(a) This Settlement Agreement is subject to approval by the Public Service Commission.

(b) Kentucky Power and the Settling Intervenors shall act in good faith and use their best efforts to recommend to the Commission that this Settlement Agreement be approved in its entirety and without modification and that the rates and charges set forth herein be implemented.

(c) Kentucky Power and the Settling Intervenors filed testimony in this case. Kentucky Power also filed testimony in support of the Settlement Agreement. For purposes of any hearing, the Settling Intervenors and Kentucky Power waive all cross-examination of the other Signatory Parties' witnesses except for purposes of supporting this Settlement Agreement unless the Commission disapproves this Settlement Agreement. Each further stipulates and recommends that the Notice of Intent, Application, testimony, pleadings, and responses to data requests filed in this proceeding be admitted into the record.

(d) The Signatory Parties further agree to support the reasonableness of this Settlement Agreement before the Commission, and to cause their counsel to do the same, including in connection with any appeal from the Commission's adoption or enforcement of this Settlement Agreement.

(e) No party to this Settlement Agreement shall challenge any Order of the Commission approving the Settlement Agreement in its entirety and without modification.

19. Failure Of Commission To Approve Settlement Agreement

If the Commission does not accept and approve this Stipulation in its entirety, then any adversely affected Party may withdraw from the Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearing's and appeals, all Parties that have not withdrawn will continue to be bound by the terms of the Stipulation as modified by the Commission's order.

20. Continuing Commission Jurisdiction

This Settlement Agreement shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

21. Effect of Settlement Agreement

This Settlement Agreement shall inure to the benefit of, and be binding upon, the parties to this Settlement Agreement, their successors, and assigns.

22. Complete Agreement

This Settlement Agreement constitutes the complete agreement and understanding among the parties to this Settlement Agreement, and any and all oral statements, representations, or agreements. Any and all such oral statements, representations, or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into this Settlement Agreement.

23. Independent Analysis

The terms of this Settlement Agreement are based upon the independent analysis of the parties to this Settlement Agreement, are the product of compromise and negotiation, and reflect a fair, just, and reasonable resolution of the issues herein. Notwithstanding anything contained in this Settlement Agreement, Kentucky Power and the Settling Intervenors recognize and agree that the effects, if any, of any future events upon the income of Kentucky Power are unknown and this Settlement Agreement shall be implemented as written.

24. Settlement Agreement And Negotiations Are Not An Admission

(a) This Settlement Agreement shall not be deemed to constitute an admission by any party to this Settlement Agreement that any computation, formula, allegation, assertion, or contention made by any other party in these proceedings is true or valid. Nothing in this Settlement Agreement shall be used or construed for any purpose to imply, suggest or otherwise indicate that the results produced through the compromise reflected herein represent fully the objectives of the Signatory Parties.

(b) Neither the terms of this Settlement Agreement nor any statements made or matters raised during the settlement negotiations shall be admissible in any proceeding, or binding on any of the parties to this Settlement Agreement, or be construed against any of the parties to this Settlement Agreement, **except that** in the event of litigation or proceedings involving the approval, implementation or enforcement of this Agreement, the terms of this Settlement Agreement shall be admissible. This Settlement Agreement shall not have any precedential value in this or any other jurisdiction.

25. Consultation With Counsel

The parties to this Settlement Agreement warrant that they have informed, advised, and consulted with their respective counsel with regard to the contents and significance of this Settlement Agreement and are relying upon such advice in entering into this agreement.

26. Authority To Bind

Each of the signatories to this Settlement Agreement hereby warrant they are authorized to sign this agreement upon behalf of, and bind, their respective parties.

27. Construction Of Agreement

This Settlement Agreement is a product of negotiation among all parties to this Settlement Agreement, and no provision of this Settlement Agreement shall be construed in favor of or against any party hereto. This Settlement Agreement is submitted for purposes of this case only and is not to be deemed binding upon the parties hereto in any other proceeding, nor is it to be offered or relied upon in any other proceeding involving Kentucky Power or any other utility.

28. Counterparts

This Settlement Agreement may be executed in multiple counterparts.

29. Future Rate Proceedings

Nothing in this Settlement Agreement shall preclude, prevent, or prejudice any party to this Settlement Agreement from raising any argument or issue, or challenging any adjustment, in any future rate proceeding of Kentucky Power.

IN WITNESS WHEREOF, this Settlement Agreement has been agreed to as of this 22nd day of November 2017.

KENTUCKY POWER COMPANY

By: ____________________

Its: Counsel

KENTUCKY INDUSTRIAL UTILITY
CUSTOMERS, INC.

By: Michael Kurtz

Its: Counsel

KENTUCKY SCHOOL BOARDS
ASSOCIATION, INC.

By: Matthan Malone

Its: Legal Counsel

KENTUCKY LEAGUE OF CITIES

By: [signature]

Its: Director of Municipal Law & Training

KENTUCKY CABLE TELECOMMUNICATION ASSOCIATION, INC.

By: Jason K[illegible]

Its: KCTA Board Chairman

WAL-MART STORES EAST, LP AND
SAM'S EAST, INC.

By: ______________________

Its: Counsel

CASE NO. 2017-00179
SETTLEMENT AGREEMENT
EXHIBIT LIST

1. Revenue Allocation
2. Rockport Offset Calculation
3. Transmission Return Difference Calculation
4. Revised Tariff P.P.A.
5. Depreciation Rates
6. Calculation of WACC and GRCF
7. Revised Tariff K-12 School
8. Revised R.P.O. Rider

EXHIBIT 1

Kentucky Power Company
Settlement Agreement Exhibit-1
Case No. 2017-00179
Settlement Revenue Allocation

Customer Class	Base Rate Case Settlement Increase: Settlement Base Rate Increase	ECP	HEAP KEDS	Total Increase	Test Year Rev	% Increase	Increase Incorporating Surcharge Changes: Carrying Charge Savings in ES	Net Increase	Total Bill % Increase	Return on Rate Base: Current ROR	Proposed ROR	Settlement: Proposed Non-Fuel Base Revenue Increase
	a	b	c	d = a+b+c	e	= d/e	f	g = d+f	= g/e			
RS	$ 20,076,436	$1,734,600	594	21,811,630	$232,952,481	9.36%	($835,019)	$20,976,611	9.00%	1.90%	3.77%	14.15%
SGS	$ 984,981	$184,183	247,506	1,416,670	$21,371,729	6.63%	($88,664)	$1,328,006	6.21%	11.30%	12.90%	7.19%
MGS	$ 3,421,623	$500,403	69,324	3,991,350	$60,245,787	6.63%	($240,889)	$3,750,461	6.23%	9.14%	10.96%	9.24%
GS*	$ 4,406,604	$ 684,586	$ 316,830	$ 5,408,020	$ 81,617,516	6.63%	($329,553)	$5,078,467	6.22%	9.67%	11.43%	8.68%
LGS/PS	$ 3,520,149	$549,861	8,467	4,078,477	$70,567,216	5.78%	($264,696)	$3,813,779	5.40%	8.78%	10.46%	8.61%
IGS	$ 3,534,466	$836,950	694	4,372,110	$157,911,866	2.77%	($402,899)	$3,969,211	2.51%	6.82%	7.71%	5.85%
MW	$ 4,956	$1,620	102	6,678	$221,405	3.02%	($780)	$5,898	2.66%	12.12%	13.02%	3.94%
OL	$ 201,254	$82,080	0	283,334	$8,984,564	3.15%	($39,512)	$243,822	2.71%	15.03%	15.68%	2.87%
SL	$ 36,869	$13,751	0	50,620	$1,645,931	3.08%	($6,620)	$44,000	2.67%	15.92%	15.84%	3.29%
Total	$ 31,780,734	$ 3,903,448	$ 326,687	$ 36,010,869	$ 553,900,979	6.50%	($1,879,080)	$34,131,789	6.16%	4.85%	5.48%	9.47%

* GS is the combination of the SGS and MGS classes

EXHIBIT 2

Kentucky Power Company
Exhibit 2 - Rockport Offset Calculation Example
Case No. 2017-00179

	*Calculation**			Source
a	12 Month GAAP Net Income	$	97,000,000	Q4 2023 Per Books as Reported SEC Kentucky Power Company
b	13 Month Average Common Equity	$	1,000,000,000	Q4 2023 Per Books as Reported SEC Kentucky Power Company
c = a/b	Return on Common Equity		9.70%	Calculation
d	Kentucky Power Allowed Retail ROE		9.75% **	Commission Order
	If D < C, Stop If D > C, Continue to Part e			
e = (b*d)-a	Net GAAP Income Increase Required to Earn Allowed Retail ROE	$	500,000	Calculation
f	Gross Revenue Conversion Factor		1.6433 **	Commission Order
g = e*f	Rockport Earnings Retainer Revenue	$	821,670	Calculation
= g	***Amount to Be Recovered Through Tariff PPA***	*$*	***821,670***	

*These numbers are illustrative
** Or as updated in a future Commission proceeding

EXHIBIT 3

Kentucky Power Company
Settlement Exhibit 3 - Transmission Return Difference Calculation
Case No. 2017-00179

	*Calculation**			*Source*	*Frequency*
a	TO Transmission Rate Base	$	319,471,085	2018 OATT TCOS	Update Annually
b	KY Juris Retail Demand Factor		0.985	2017-00179 Section V, Allocation Factors	Remains Static
c = a*b	KY Retail TO Trans Rate Base	$	314,679,018	calculation	
d	Base Rate KY Retail Trans Rate Base	$	266,193,980	2017-00179 Class Cost of Service	Remains Static
e = c-d	Difference	$	48,485,038	calculation	
f	TO WACC @ 11.49 ROE		7.55%	2018 OATT TCOS	Update Annually
g	TO WACC @ 9.75 ROE		6.78%	2018 OATT TCOS	Update Annually
h = f-g	Difference		0.77%	calculation	
j = e*h	TO Return Delta	$	371,431	calculation	
k	GRCF		1.6351	2018 OATT TCOS	Update Annually
= j*k	*2018 Tariff PPA Revenue Credit*	*$*	*607,326*	calculation	Update Annually

*These numbers are illustrative

EXHIBIT 4

KENTUCKY POWER COMPANY P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 35-1
CANCELLING P.S.C. KY. NO. 11 _________ SHEET NO. 35-1

TARIFF P.P.A.
(Purchase Power Adjustment)

APPLICABLE.

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., K-12 School, L.G.S., L.G.S.-T.O.D., I.G.S., C.S. – I.R.P., M.W., O.L. and S.L.

RATE.

The annual purchase power adjustment factor will be computed using the following formula:

1. Annual Purchase Power Net Costs (PPANC)

PPANC = N+RP+CSIRP+G+OATT+RKP-BPP

Where:

BPP = The annual amount of purchase power costs included in base rates, $78,737,938.

a. N = The annual cost of power purchased by the Company through new Purchase Power Agreements. All new purchase power agreements shall be approved by the Commission to the extent required by KRS 278.300.
b. RP = The annual purchased power costs not otherwise recoverable in the Fuel Adjustment Clause including but not limited to the cost of fuel related substitute generation less the cost of fuel which would have been used in plants suffering forced generation or transmission outages and the cost of purchases in excess of the highest cost owned or leased unit.
c. CSIRP = The net annual cost of any credits provided to customers under Tariff C.S.-I.R.P. for interruptible service.
d. G = The annual gains and losses on incidental gas sales; and
e. OATT = 80% The net annual PJM load-serving entity Open Access Transmission Tariff Charges above or below the $74,038,517 included in BPP, less the transmission return difference pursuant to the Commission approved Settlement agreement in Case No. 2017-00179.
f. RKP = Rockport related items includable in Tariff PPA pursuant to the Commission approved Settlement agreement in Case No. 2017-00179:
   i. Increase in Rockport collection resulting from reduction in base rate deferral;
   ii. Rockport deferral amount to be recovered;
   iii. Rockport fixed cost savings; and
   iv. Rockport offset estimate and true-up.
   v. Final (over)/under recovery associated with tariff CC following its expiration

T
T

(Cont'd on Sheet No. 35-2)

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 35-2
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 35-2

N

TARIFF P.P.A. (Cont'd)
(Purchase Power Adjustment)

RATES.

Tariff Class	\$/kWh	\$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.	\$0.00000	--
S.G.S.-T.O.D.	\$0.00000	--
M.G.S.-T.O.D.	\$0.00000	--
G.S.	\$0.00000	--
L.G.S., P.S, L.G.S.-T.O.D.	\$0.00000	\$0.00
L.G.S.-L.M.-T.O.D.	\$0.00000	--
I.G.S. and C.S.-I.R.P.	\$0.00000	\$0.00
M.W.	\$0.00000	--
O.L.	\$0.00000	--
S.L.	\$0.00000	--

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the LGS and IGS tariff classes.

The Purchase Power Adjustment factors shall be modified annually using the following formula:

The Purchase Power Adjustment factors shall be determined as follows:
For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total}) + PPA(D) \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{PPA(D) \times (CP_{Class} / CP_{Total})}{BD_{Class}}$$

N

(Cont'd on Sheet No. 35-3)

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

In Case No. 2017-00179 Dated XXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 35-3**
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 35-3

N

TARIFF P.P.A. (Cont'd)
(Purchase Power Adjustment)

RATES. (Cont'd)

Where:

1. "PPA(D)" is the actual annual retail PPA demand-related costs, plus any prior review period (over)/under recovery.
2. "PPA(E) is the actual annual retail PPA energy-related costs, plus any prior review period (over)/under recovery.
3. "BE_{Class}" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.
4. "BD_{Class}" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.
5. "CP_{Class}" is the coincident peak demand for each tariff class estimated as follows:

Tariff Class	BE_{Class}	CP/kWh Ratio	CP_{Class}
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.		0.0240909%	
S.G.S.-T.O.D.		0.0196553%	
M.G.S.-T.O.D.		0.0196553%	
G.S.		0.0196553%	
L.G.S., P.S, L.G.S.-T.O.D		0.0170480%	
L.G.S.-L.M.-T.O.D.		0.0170480%	
I.G.S. and C.S.-I.R.P.		0.0118222%	
M.W.		0.0135480%	
O.L.		0.0000000%	
S.L.		0.0000000%	

6. "BE_{Total}" is the sum of the BE_{Class} for all tariff classes.
7. "CP_{Total}" is the sum of the CP_{Class} for all tariff classes.
8. The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.34% and the KPSC Maintenance Fee of 0.1996% and other similar revenue based taxes or assessments occasioned by the Purchase Power Adjustment revenues.
9. The annual PPA factors shall be filed with the Commission by August 15 of each year with the exception of the Rockport items includable in Tariff PPA pursuant to the Commission approved Settlement agreement in Case No. 2017-00179, with rates to begin with the October billing period, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884. N

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

EXHIBIT 5

Exhibit 5 - Depreciation Rates
Case No. 2017-00179

KENTUCKY POWER COMPANY
BIG SANDY UNIT 1 AND MITCHELL PLANT SETTLEMENT DEPRECIATION RATES CALCULATION
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013 (MITCHELL) AND AT DECEMBER 31, 2016 (BIG SANDY UNIT 1)
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

									Annual Accrual	
Acct.	Title	Original Cost	Net Salvg. Ratio	Total to be Recovered	Calculated Depreciation Requirement	Accumulated Depreciation	Remaining to Be Recovered	Avg. Remain Life	Amount	Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
STEAM PRODUCTION PLANT										
Big Sandy Unit 1										
311.0	Structures & Improvements	11,756,127	1.02	11,991,250	7,526,502	4,805,397	7,185,853	20.00	359,293	3.06%
312.0	Boiler Plant Equipment	75,388,722	1.02	76,896,496	22,552,265	9,774,280	67,122,216	20.00	3,356,111	4.45%
314.0	Turbogenerator Units	61,392,346	1.02	62,620,193	36,338,075	28,424,981	34,195,212	20.00	1,709,761	2.78%
315.0	Accessory Electrical Equip.	3,877,136	1.02	3,954,679	2,964,549	2,578,951	1,375,728	20.00	68,786	1.77%
316.0	Misc. Power Plant Equip.	3,321,344	1.02	3,387,771	2,153,127	1,512,867	1,874,904	20.00	93,745	2.82%
	Total	155,735,675		158,850,389	71,534,518	47,096,476	111,753,913		5,587,696	3.59%
Mitchell Plant										
311	Structures & Improvements	42,000,197	1.03	43,260,203	18,282,178	16,183,402	27,076,801	25.01	1,082,639	2.58%
312	Boiler Plant Equipment	765,644,984	1.03	788,614,334	245,324,500	238,518,432	550,095,902	24.25	22,684,367	2.96%
312	Boiler Plant Equip SCR Catalyst	8,190,115	1.00	8,190,115	4,023,394	2,378,493	5,811,622	4.07	1,023,764	12.50%
314	Turbogenerator Units	53,295,697	1.03	54,894,568	29,106,660	33,613,523	21,281,045	23.84	892,661	1.67%
315	Accessory Electrical Equip.	17,080,672	1.03	17,593,092	9,466,086	11,043,285	6,549,807	25.81	253,770	1.49%
316	Misc. Power Plant Equip.	7,693,412	1.03	7,924,214	3,289,590	3,072,520	4,851,694	23.96	202,491	2.63%
	Total	893,905,077	1.03	920,476,526	309,492,408	304,809,655	615,666,871	23.55	26,139,693	2.92%

Notes:
1.) Terminal net salvage removed as a component of net salvage ratio for both plants (column IV).
2.) Average remaining life adjusted to reflect a 20 year useful life of BS1 (column IX).
3.) Mitchell Plant information from schedule used to calculate depreciation rates in settlement of Case No. 2014-00396.

EXHIBIT 6

Kentucky Power Company
Exhibit 6a - Calculation of Weighted Average Cost of Capital
Case No. 2017-00179

KENTUCKY POWER COMPANY
COST OF CAPITAL
TEST YEAR ENDED FEBRUARY 28, 2017

Line No.	Description	Reapportioned Kentucky Jurisdictional Capital 1/	Percentage of Total	Annual Cost Percentage Rate		Weighted Average Cost Percent	Gross Up	Pre-Tax Weighted Average Cost Percent
(1)	(2)	(3)	(4)	(5)		(6) = (4) X (5)	(7)	(8) = (6) X (7)
1	Long Term Debt	$636,995,903	53.45%	4.36%	2/	2.33%	1.00540	2.34%
2	Short Term Debt	11,917,855	1.00%	1.25%	3/	0.01%	1.00540	0.01%
3	Accounts Receivable F	46,105,009	3.87%	1.95%	5/	0.08%	1.00540	0.08%
4	Common Equity	496,766,726	41.68%	9.75%	6/	4.06%	1.64334	6.67%
5	Total	$1,191,785,493	100.00%			6.48%		9.11%

Kentucky Power Company
Exhibit 6b - Calculation of Gross Revenue Conversion Factor
Case No. 2017-00179

KENTUCKY POWER COMPANY
COMPUTATION OF THE GROSS REVENUE
CONVERSION FACTOR
TEST YEAR ENDED FEBRUARY 28,2017

Line No. (1)	Description (2)		Percent of Incremental Gross Revenues (3)
1	Operating Revenues		100.00%
2	Less: Uncollectible Accounts Expense 1/		0.3400%
3	KPSC Maintenance Fee		0.1996%
4	Income Before income Taxes		99.4604%
5	Less: State Income Taxes (L4 X 5.8742%) 2/	5.87%	5.843%
6	Income Before Federal Income Taxes		93.6179%
7	Less: Federal income Taxes (L6 X 35.00%)	35.00%	32.7663%
8	Operating Income Percentage		60.8516%
9	Gross Revenue Conversion Factor (100% / L8)		**1.6433**

EXHIBIT 7

KENTUCKY POWER COMPANY P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 9-9
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 9-9

TARIFF K-12 SCHOOL
(Public and Private School)

AVAILABILITY OF SERVICE.

Available for general service to K-12 School customers subject to KRS 160.325 with normal maximum demands greater than 100 KW but not more than 1,000 KW.

RATE.

	Service Voltage			
	Secondary	Primary	Subtransmission	Transmission
Tariff Code	260	264	268	270
Service Charge per Month	$ 85.00	$ 127.50	$ 660.00	$ 660.00
Demand Charge per KW	$ 7.97	$ 7.18	$ 5.74	$ 5.60
Excess Reactive Charge per KVA	$ 3.46	$ 3.46	$ 3.46	$ 3.46
Energy Charge per KWH	7.671¢	6.709¢	5.535¢	5.429¢

MINIMUM CHARGE.

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

ADJUSTMENT CLAUSES.

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 5
System Sales Clause	Sheet No. 19
Franchise Tariff	Sheet No. 20
Demand-Side Management Adjustment Clause	Sheet No. 22
Kentucky Economic Development Surcharge	Sheet No. 24
Capacity Charge	Sheet No. 28
Environmental Surcharge	Sheet No. 29
School Tax	Sheet No. 33
Purchase Power Adjustment	Sheet No. 35
Decommissioning Rider	Sheet No. 38

(Cont'd on Sheet No. 9-10)

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

TARIFF K-12 SCHOOL (Cont'd)
(Public and Private School)

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

DETERMINATION OF EXCESS KILOVOLT-AMPERE (KVA) DEMAND.

The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

(Cont'd on Sheet No. 9-11)

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[redacted]

In Case No. 2017-00179 Dated XXXXXXX

TARIFF K-12 SCHOOL (Cont'd)
(Public and Private School)

TERM OF CONTRACT.

Contracts under this tariff will be made for customers requiring a normal maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than 1 (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

CONTRACT CAPACITY.

The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

EXHIBIT 8

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 31-1**
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 31-1

RIDER R.P.O.
(Renewable Power Option Rider)

AVAILABILITY OF SERVICE.

Available to customers taking metered service under the Company's R.S., R.S.D. , R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., K-12 School, L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P. and M.W. tariffs. T T

Participation in this program under Option A may be limited by the ability of the Company to procure renewable energy certificates (RECs) from Renewable Resources. If the total of all kWh under contract under this Rider equals or exceeds the Company's ability to procure RECs, the Company may suspend the availability of this Rider to new participants. T

Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. tariffs, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1000 kW of peak demand. N N

CONDITIONS OF SERVICE.

Customers who wish to support the development of electricity generated by Renewable Resources may under Option A contract to purchase each month a specific number of fixed kWh blocks, or choose to cover all of their monthly usage. T T

Renewable Resources shall be defined as Wind, Solar Photovoltaic, Biomass Co-Firing of Agricultural crops and all energy crops, Hydro (as certified by the Low Impact Hydro Institute), Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-Firing of All Woody Waste including mill residue, but excluding painted or treated lumber. All REC's purchased under Option A of this tariff shall be retained or retired by the Company on behalf of customers. T T T

RATES.

Option A: N

In addition to the monthly charges determined according to the Company's tariff under which the customer takes metered service, the customer shall also pay the following rate for the REC option of their choosing. The charge will be applied to the customer's bill as a separate line item. T

The Company will provide customers at least 30-days' advance notice of any change in the Rate. At such time, the customer may modify or cancel their automatic monthly purchase agreement. Any cancellation will be effective at the end of the current billing period when notice is provided.

A1. Solar RECs:

Block Purchase:	Charge ($ per 100 kWh block): $ 1.00/month	N
All Usage Purchase:	Charge: $0.010/kWh consumed	N

(Cont'd on Sheet 31-2)

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By Authority Of an Order of the Public Service Commission

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KENTUCKY POWER COMPANY

P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 31-2
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 31-2

RIDER R.P.O. T
(Renewable Power Option Rider) T

RATES. (Cont'd)

N

A2. Wind RECs:

Block Purchase: Charge ($ per 100 kWh block): $ 1.00/month
All Usage Purchase: Charge: $0.010/kWh consumed

A3. Hydro & Other RECs:

Block Purchase: Charge ($ per 100 kWh block): $ 0.30/month
All Usage Purchase: Charge: $0.003/kWh consumed

Option B:

Charges for service under option B of this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect a combination of the firm service rates otherwise available to the Customer and the cost of the renewable energy resource being directly contracted for by the Customer. N

TERM.

This is a voluntary program.

Under Option A Customers may participate through a one-time purchase, or establish an automatic monthly purchase agreement. Any payments under this program are nonrefundable. Customers participating under Option A may terminate service under this Rider by notifying the Company with at least thirty (30) days prior notice. T T T

Under Option B, the term of the agreement will be determined in the written agreement between the Company and the Customer. T

SPECIAL TERMS AND CONDITIONS.

This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. The Company may deny or terminate service under this Rider to customers who are delinquent in payment to the Company.

Funds collected under this Renewable Power Option Rider will be used solely to purchase RECs for the program. T

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KENTUCKY POWER COMPANY P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 31-3
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 31-3

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By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

RRA Regulatory Focus

Quarterly State Regulatory Evaluations

May 30, 2022

RRA State Regulatory Evaluations — Energy

Lillian Federico **Research Director, Energy**

Contributors: **Brian Collins, Jim Davis, Russell Ernst, Lisa Fontanella, Monica Hlinka, Jason Lehman, Dan Lowrey**

Regulatory Research Associates, a group within S&P Global Commodity Insights, evaluates the regulatory climate for energy utilities in each of the jurisdictions within the 50 states and the District of Columbia — a total of 53 jurisdictions — on an ongoing basis. S&P Global Commodity Insights produces content for distribution on S&P Capital IQ Pro. In a recent review, RRA made changes to the ranking of the Kentucky and Railroad Commission of Texas.

For detailed data

Access the RRA Evaluations Report Supplemental Data

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Executive Summary

Introduction

While significant regulatory developments have been taking place for energy utilities in recent months. Regulatory Research Associates is, at this time, maintaining the regulatory rankings of the jurisdictions under coverage.

RRA evaluates the regulatory climate for energy utilities in each of the jurisdictions within the 50 states and the District of Columbia — a total of 53 jurisdictions — on an ongoing basis. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by each jurisdiction's energy utilities.

Each evaluation is based upon consideration of the numerous factors affecting the regulatory process, including gubernatorial involvement, legislation and court activity, and may be adjusted as events occur that cause RRA to modify its view of the regulatory risk for a given jurisdiction.

RRA also reviews evaluations as key rate case and other regulatory decisions are issued when updating Commission Profiles and publishing this quarterly comparative report. The issues considered are discussed in RRA Research Notes, Commission Profiles, Topical Special Reports and Rate Case Analyses. RRA also considers information obtained from contacts with commission, company and government personnel in the course of its research. The final evaluation is an assessment of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative and court actions.

About This Report

This report provides a discussion of recent changes in RRA's energy regulatory rankings, with details regarding the rationale for these changes. The report also identifies jurisdictions where there are ongoing proceedings or developing issues that have the potential to impact the relative regulatory risk for utilities operating within a given jurisdiction and, by extension, the ranking of that jurisdiction. RRA also highlights broad-based trends and issues that have implications for utilities across jurisdictions. Finally, the report includes an overview of RRA's ranking methodology and the issues RRA examines in deriving the rankings.

Key Findings

- While significant developments have occurred across the U.S. in recent months, recent regulatory outcomes did not warrant a change to the ranking of any individual jurisdiction under coverage.
- Even so, RRA has identified seven jurisdictions that warrant enhanced scrutiny based on recent or upcoming developments.
- There are several trends/issues that have broad-reaching effects that will impact utilities across the U.S. in the coming months.
- The 2022 midterm elections could lead to changes in regulatory policy across the U.S.

The Take

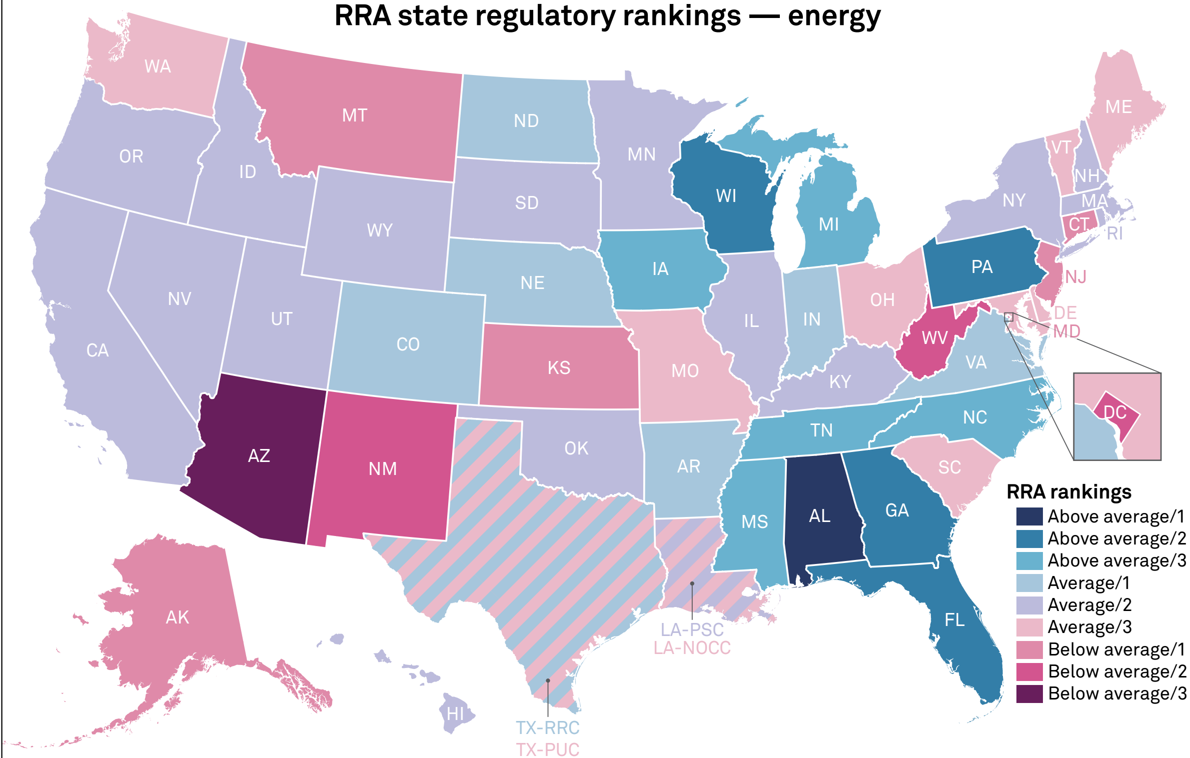
While developments continue to unfold on a variety of key issues across the regulated utility sector nationwide, none have caused a significant relative shift in RRA's assessment of regulatory risk in any individual jurisdiction. As such, RRA is maintaining the current ranking of each of the 53 covered jurisdictions at this time.

Nevertheless, several jurisdictions bear watching closely, as pending proceedings and/or legislation could lead to a change in RRA's assessment of the regulatory climate in those jurisdictions.

From a wider perspective, several overarching issues present challenges for utilities and regulators across the U.S. and warrant close observation. How regulators address these issues will be key to utilities' financial performance in the coming years. These include long-term concerns such as the ongoing energy transition and the potential for stranded costs, severe winter events, inflation and rising interest rates and COVID-19 related considerations. The ongoing conflict in the Ukraine could also have indirect implications for the U.S. energy utilities.

In addition, gubernatorial elections will be held in 37 jurisdictions in 2022. With increased emphasis on energy and energy transition issues observed in recent years, changes in the chief executive of the jurisdiction could have meaningful impacts on utility-related policymaking, as well as bringing changes to the makeup of the regulatory bodies in jurisdictions where the chief executive selects the commissioners.

RRA state regulatory rankings — energy



Data compiled May 27, 2022.
NOCC = New Orleans City Council; RRC = railroad commission
Map credit: Joe Felizadio
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

Recent ranking changes

At this time, RRA is making no ranking changes as opposed to the prior quarterly review of the rankings where the team made two ranking changes.

The team lowered the ranking of Kentucky regulation to Average/2 from Average/1 to account for the Kentucky Public Service Commission's pattern of modifying or rejecting rate case settlements over the preceding months.

RRA raised the ranking of the Texas RRC jurisdiction to Average/1 from Average/2 in recognition of the constructive treatment accorded extraordinary commodity costs incurred by the local gas distribution utilities during the February 2021 extreme weather event known as Winter Storm Uri.

RRA state regulatory evaluations

State-by-state listing — energy

Jurisdiction	Ranking	Jurisdiction	Ranking	Jurisdiction	Ranking
Alabama	Above Average/1	Louisiana — NOCC	Average/3	Ohio	Average/3
Alaska	Below Average/1	Louisiana — PSC	Average/2	Oklahoma	Average/2
Arizona	Below Average/3	Maine	Average/3	Oregon	Average/2
Arkansas	Average/1	Maryland	Average/3	Pennsylvania	Above Average/2
California	Average/2	Massachusetts	Average/2	Rhode Island	Average/2
Colorado	Average/1	Michigan	Above Average/3	South Carolina	Average/3
Connecticut	Below Average/1	Minnesota	Average/2	South Dakota	Average/2
Delaware	Average/3	Mississippi	Above Average/3	Tennessee	Above Average/3
District of Columbia	Below Average/2	Missouri	Average/3	Texas — PUC	Average/3
Florida	Above Average/2	Montana	Below Average/1	Texas — RRC	Average/1
Georgia	Above Average/2	Nebraska	Average/1	Utah	Average/2
Hawaii	Average/2	Nevada	Average/2	Vermont	Average/3
Idaho	Average/2	New Hampshire	Average/2	Virginia	Average/1
Illinois	Average/2	New Jersey	Below Average/1	Washington	Average/3
Indiana	Average/1	New Mexico	Below Average/2	West Virginia	Below Average/2
Iowa	Above Average/3	New York	Average/2	Wisconsin	Above Average/2
Kansas	Below Average/1	North Carolina	Above Average/3	Wyoming	Average/2
Kentucky	Average/2	North Dakota	Average/1		

Data compiled May 27, 2022.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

Jurisdictions to watch

In addition to the above-discussed ranking changes, there are several jurisdictions where ongoing trends could signal a shift in the level of regulatory risk for investors.

In RRA's view, the **California** regulatory climate bears continued watching in a few respects. The probation judge overseeing Pacific Gas & Electric Co.'s five-year felony probation, which ended Jan. 25, called the company a "continuing menace" and suggested that customer safety might better be served if the utility was broken up. Separately, the California Public Utilities Commission is moving forward with proposed changes to its solar net metering policy. The proposal would slash payments for solar power exported to the grid under the state's net energy metering program, impose new fixed charges and negate a previously agreed-upon grandfathering policy. A decision could come this summer. And finally, legislation working through the California State Senate and Assembly could promote undergrounding of utility power lines, providing benefits to customers while helping electric utilities attract capital.

In the **District of Columbia**, the PSC's approval of a first-of-its-kind multiyear rate plan for Exelon Corp. subsidiary Potomac Electric Power Co., is still on appeal before the courts. There are also several ongoing grid modernization-related proceedings that bear watching and Alta Gas Ltd. subsidiary Washington Gas Light Co. is in the midst of a contentious rate case. In addition, for some time there has been a vacancy on the commission resulting from the appointment of former chairman Willie Phillips to the Federal Energy Regulatory Commission. In addition, another commissioner's term will be expiring in June.

After having lowered the ranking of **Kentucky** regulation to Average/2 from Average/1 in the prior review, RRA still views Kentucky as a jurisdiction that bears watching, as there has been considerable turnover at the PSC in recent months. The only current member of the PSC is Chairman Kent Chandler, a Democrat, who is serving a term extending to June 30, 2024. Chandler was the sole signatory on the commission's May 4 order approving the sale of American Electric Power Co. Inc.'s Kentucky Power Co. electric utility to a subsidiary of Algonquin Power & Utilities Corp. Gov. Andy Beshear, a Democrat, appointed Marianne Butler to the PSC on Sept. 10, 2021, for a term extending to June 30, 2025. Butler's appointment to the PSC was subsequently rejected by the state Senate, and the seat became vacant. Amy Cubbage was appointed to the PSC to fill an unexpired term extending to June 30, 2023; Cubbage was also named vice chairman. The Senate did not confirm the nomination during the 2022 session requiring Cubbage to leave the commission.

In **Pennsylvania**, ongoing tension between the Republican-controlled Senate and Gov. Tom Wolfe, a Democrat, bears watching. The Senate has opposed the governor's moves to implement energy transition-related initiatives, such as joining the Regional Greenhouse Gas Initiative, or RGGI, without enabling legislation and related appeals are currently before the state courts. Absent a stay, the Pennsylvania Department of Environmental Quality's carbon-trading rules would become effective in July, facilitating the state's participation in RGGI. The Senate indicated in April 2021 that it would not act to confirm new appointees to the Pennsylvania Public Utility Commission until/unless the governor rescinds his directives. As a result, there are now two vacancies on the five-member commission, and another commissioner term expired in April 2022; the commissioner may continue to serve for six months beyond the end of the term. However, if a new member is not appointed and confirmed by that time, the commission would be down to two members. While the PUC apparently could continue to operate with just two members, there would be the potential for tie votes that would prevent decisions from being issued on key matters.

As the controversy wears on, the outcome of the upcoming gubernatorial election takes on increasing significance. Wolf, serving a second consecutive term, cannot run in the November general election. Consequently, there will be a new governor in Pennsylvania come January 2023. Since the carbon-trading rules were not implemented by statute, a new governor could theoretically roll back or alter the rules administratively. In addition, a change in the political party makeup of the legislature could change the landscape for enacting legislation to either require or block Pennsylvania's participation in carbon cap-and-trade markets.

The **South Carolina** regulatory climate bears watching, as utility-supported legislation has passed the state Senate and is now being heard in the House. If enacted, this legislation would provide an additional tool — securitization — to recover prior and future storm restoration costs, creating savings for customers as compared to traditional recovery mechanisms and allowing utilities more expeditious recovery of such costs, thus reducing regulatory risk.

For the last year, the **Public Utility Commission of Texas** and lawmakers have been focused on changes to the structure of the electric power market within the Electric Reliability Council of Texas, or ERCOT, the makeup of the PUC and ERCOT, and electric system reliability and resiliency issues in the wake of power outages and price spikes that occurred during a severe weather event in February 2021. RRA believes that the Texas climate continues to bear enhanced scrutiny due to the ongoing transition in PUC membership. In RRA's view, appointments made to replace the previous commission members who resigned, as well as those made to fill the new seats on the commission resulting from the expansion of PUC to five members from three, has created a body whose members have little in the way of a track record with respect to their current roles. However, one of the newly seated commissioners was formerly the head of the Office of Public Utility Counsel, which represents consumer interests before the PUC. That commissioner has had to recuse themselves from several proceedings due to previous involvement with the issues at hand. There also continues to be one vacancy on the commission. Further complicating matters, a gubernatorial election will take place in Texas in November 2022. Incumbent Republican Gov. Greg Abbott will be seeking reelection. Abbott will face

Democrat Beto O'Rourke, who won the March primary. Lt. Gov. Dan Patrick, who though a Republican was critical of Abbott's and the PUC's handling of the February 2021 weather event, will be seeking reelection. Patrick will be facing Democrat Rochelle Garza and the winner of a runoff primary against opponent Joe Jaworski.

In RRA's view, the **Virginia** regulatory climate also bears watching. Under the leadership of former Gov. Ralph Northam, a Democrat, policymakers focused on renewables and alternative technologies. With the Nov. 2, 2021 general election, Virginia saw a change not only in the governor but also the governor's political party, as Republican Glenn Youngkin defeated Democrat Terry McAuliffe. In addition, Republicans gained control of the House of Delegates. Immediately upon taking office in January 2022, Youngkin issued an executive order that seeks to "re-evaluate Virginia's participation in the [RGGI] and immediately begin regulatory processes to end it." The order followed an opinion issued by Virginia Attorney General Mark Herring, stating that the Virginia governor cannot, by executive order or another administrative remedy, withdraw Virginia from the RGGI. While legislation was passed by the House during the now-adjourned 2022 session that would have rolled back some of the energy transition initiatives implemented by the prior administration, the measure did not progress in the Senate. In addition, the General Assembly adjourned without selecting a successor to fill the vacancy left on the Virginia State Corporation Commission, when Angela Navarro's term ended in February. By law, Youngkin could fill the vacancy on an interim basis, until the legislature convenes in 2023, but has not done so.

RRA State Regulatory Evaluations — Energy*

(By category, states to watch highlighted)

Above Average/1	Above Average/2	Above Average/3	Average/1	Average/2	Average/3	Below Average/1	Below Average/2	Below Average/3
Alabama	Florida	Iowa	Arkansas	California	Delaware	Alaska	Dist. of Columbia	Arizona
	Georgia	Michigan	Colorado	Hawaii	Louisiana — NOCC	Connecticut	New Mexico	
	Pennsylvania	Mississippi	Indiana	Idaho	Maine	Kansas	West Virginia	
	Wisconsin	North Carolina	Nebraska	Illinois	Maryland	Montana		
		Tennessee	North Dakota	Kentucky	Missouri	New Jersey		
			Texas — RRC	Louisiana — PSC	Ohio			
			Virginia	Massachusetts	South Carolina			
				Minnesota	Texas — PUC			
				Nevada	Vermont			
				New York	Washington			
				New Hampshire				
				Oklahoma				
				Oregon				
				Rhode Island				
				South Dakota				
				Utah				
				Wyoming				

Data compiled May 27, 2022.
NOCC = New Orleans City Council; PUC = Public Utility Commission; RRC = Railroad Commission
* Within a given subcategory, states are listed in alphabetical order, not by relative ranking.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

Issues to watch

At any given point in time, there may be macroeconomic or broad industry issues and trends that can positively or negatively affect the level of risk facing utilities and impact their financial performance. While these issues in and of themselves do not necessarily impact the relative rankings of the individual jurisdictions RRA follows, how a given jurisdiction addresses these factors may impact the relative regulatory risk for the entities operating in that jurisdiction. This section discusses the issues that, in RRA's view, are currently top of mind for industry stakeholders.

Inflation and rising interest rates pose challenges for recovery of capital investment

The introduction of significant inflation for the first time in decades, coupled with rising interest rates, will drive increasing rate case activity and put upward pressure on overall rate levels. This will reduce the headroom for utilities to achieve recovery of costs associated with aggressive capital spending plans, energy transition costs, stranded costs, rising input costs associated with supply chain issues that have developed in the wake of Russia's invasion of the Ukraine and the COVID-19 pandemic.

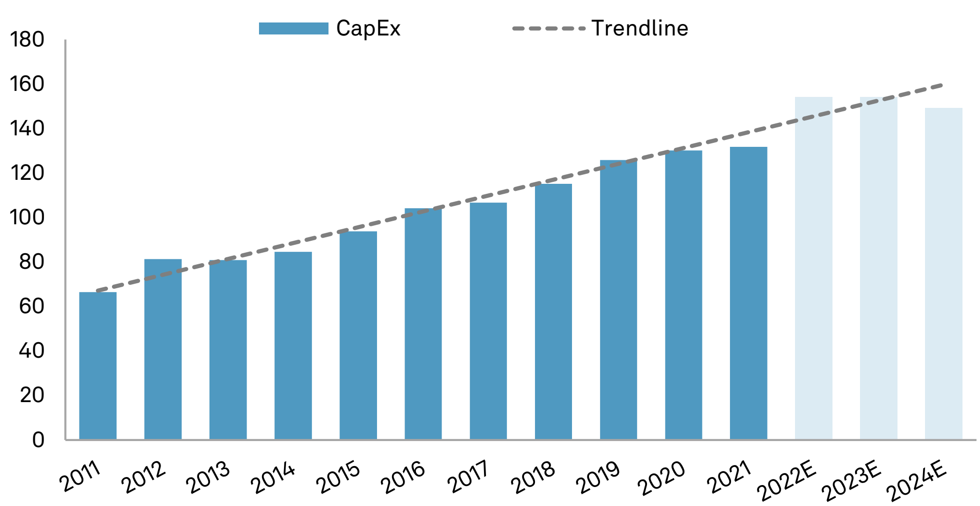
In 2021, retail electric prices in the U.S. rose on an inflation-adjusted basis, after registering inflation-adjusted declines in the prior three calendar years.

The nation's energy utilities are investing in infrastructure to upgrade aging transmission and distribution systems, build new natural gas, solar and wind generation assets and implement new technologies, including smart meter deployment, smart grid systems, cybersecurity measures, electric vehicles and battery storage.

On a nominal basis, electric prices rose more than 5% on average in 2021 versus 2020. In light of heightened geopolitical risks and supply chain and raw materials issues in multiple industries, nominal and real retail electric prices will likely increase in 2022. As measured by the consumer price index, inflation was 8.54% higher in March 2022 than in March 2021.

Projected 2022 capital expenditures for the 47 energy utilities included in RRA's representative sample of publicly traded U.S.-based utility universe currently exceeds $154 billion, well above almost $132 billion of actual investment reported for 2021.

Energy utility actual and estimated capex ($B)



Compiled March 30, 2022.
Source: S&P Global Market Intelligence

The aggregated forecast for 2023 capex again points to over $154 billion of spending. While the 2024 estimate of $149.3 billion appears to signal the potential for a slight decline in capex compared with 2022 and 2023, it is anticipated that annual investments will ultimately be successively higher in each following year. In nine out of the last 10 years, annual investments exceeded the prior year, even though initial forecasts called for declines in the latter years.

Planned 2022 spending on electric transmission and distribution projects aggregates to almost $65 billion, while renewables spending is projected to total over $19 billion.

To combat inflation, the U.S. Federal Reserve has embarked on a course of interest rate hikes, the first of which began in March, with incremental increases expected in coming months.

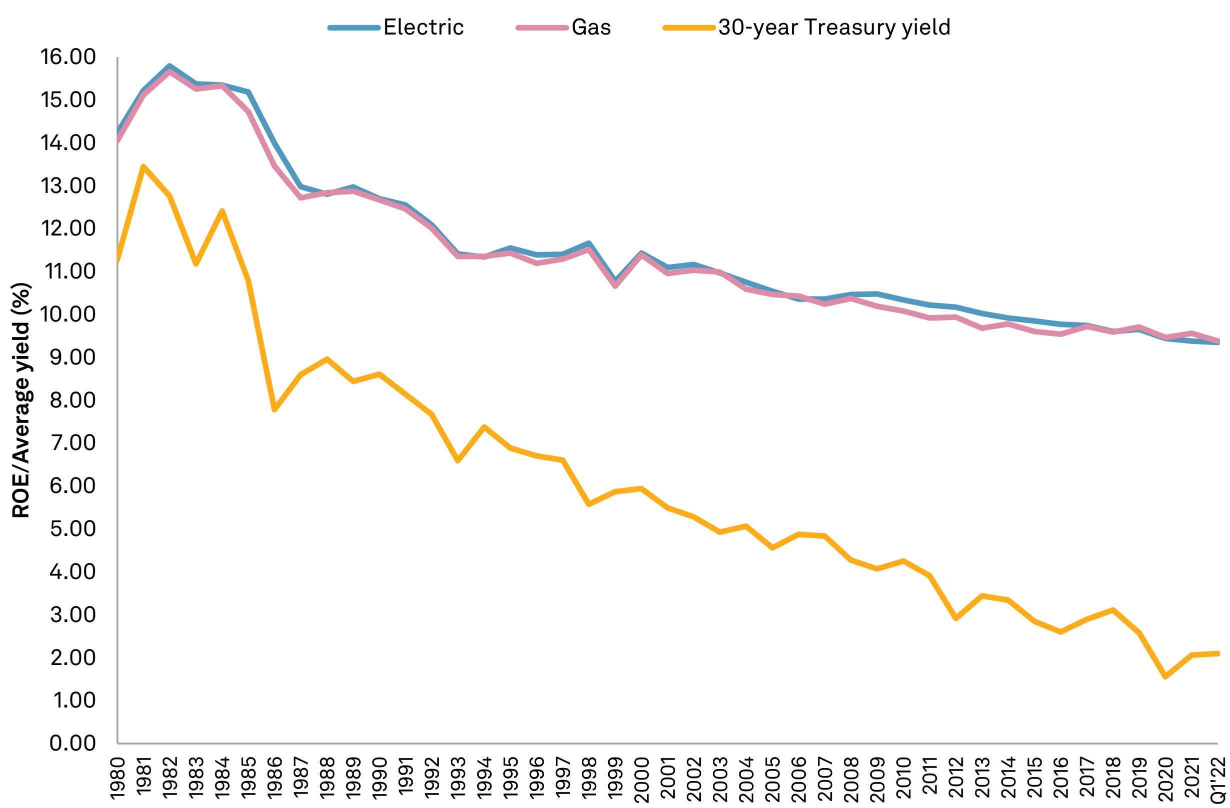
Rising interest rates would seem to imply that authorized ROEs, which have been on a downward trajectory for the last four decades, should begin to rise. However, this may not be the case.

The authorized ROE is one of the most highly contested and subjective issues addressed in a rate case. While there are well-known formulas that are commonly used to establish the authorized ROE, such as the discounted cash flow, risk premium and capital asset pricing models, these formulas require subjective judgments with respect to risk, expected growth and what exactly it is investors require to ensure adequate access to capital.

Historically, authorized ROEs have generally followed the direction of interest rates, but there is often a lag because of the amount of time it takes to prepare, file and complete rate cases, because regulators often adhere to a concept of gradualism that smooths out the changes, and because of subjective judgement, which is often influenced by macroeconomic factors.

Average authorized ROE in the US/30-year Treasury bond yields

Calendar years 1980-2021, Q1'22



Data compiled as of May 27, 2022.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights; U.S. Department of the Treasury

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The average ROE authorized for electric utilities reached an all-time low of 9.38% in 2021 versus the 9.44% average for cases decided in 2020. For the first quarter of 2022, the average ROE approved for electric utilities fell slightly to 9.35%.

By contrast, the average ROE authorized for gas utilities was 9.56% for cases decided during 2021, up from the 9.46% average observed in 2020, but still near historical lows. However, the average equity return authorized in gas cases dropped to 9.38% in the first quarter of 2022.

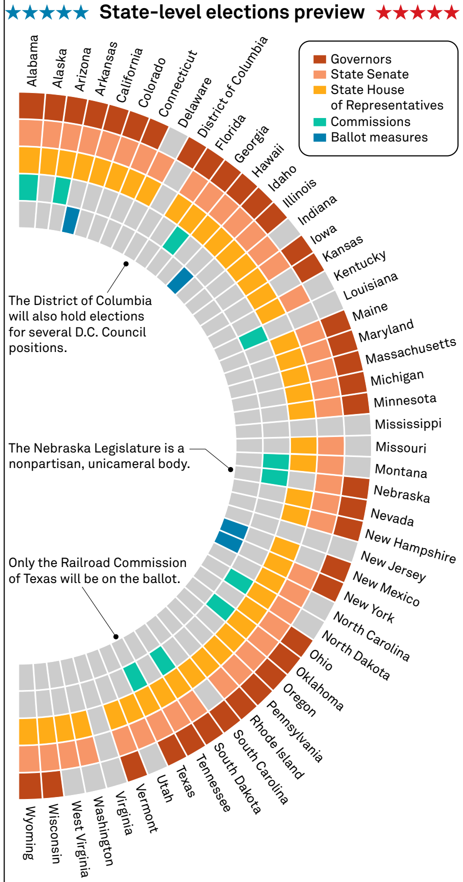
The last time the industry faced rising inflation and interest rates during a period of aggressive capital spending was in the early 1980s. For the years 1980 through 1984, the spread between the average authorized ROEs documented by RRA and treasury yields averaged 292 basis points. By contrast, during the years 2006 through 2010, the average spread had widened to 587 basis points. Spreads continued to expand thereafter, reaching close to 800 basis points in 2020.

In 2021, the spread narrowed a bit to around 740 basis points. Using history as a guide, it appears likely that as interest rates continue to rise, the spread will narrow further. While this may not lead to a continued decline in authorized ROEs, they may well remain flat or rise at a significantly more modest rate than interest rates.

Alternatively, regulators may direct utilities to scale back or postpone capital spending initiatives that could work to slow down the energy transition.

2022 elections could lead to shifts in public policy in several states

★★★★★ State-level elections preview ★★★★★



Data as of March 23, 2022.
Only official ballot measures that may effect the energy industry, directly or indirectly, were included. In several states, there are measures going through the signature gathering process.
Credit: Arleigh Andes
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

The Nov. 8, 2022 midterm elections will involve 36 gubernatorial elections and a mayoral election in the District of Columbia, 88 legislative chambers and 17 utility commissioners across 10 states.

In 26 of the 36 states that will be electing their governors, the incumbent governor is seeking reelection. In the District of Columbia, incumbent Mayor Muriel Bowser, a Democrat, is also seeking reelection.

In two states — Vermont and Wyoming — the incumbent has not announced whether they will be running for reelection.

In seven of the gubernatorial races, the incumbent is ineligible to seek reelection, and in one state — Massachusetts. —, the incumbent has declined to run.

In 27 of the 37 jurisdictions, including the District of Columbia, where the chief executive is up for election, the chief executive appoints regulators to the applicable utility commission.

Additionally, in 20 of the 27 jurisdictions, the chief executive of the jurisdiction appoints the chairman of the respective regulatory body.

In the jurisdictions where the chief executive appoints the utility commissioners, 27 commissioner terms are set to expire within the first year of the executive's new term.

A new governor/mayor can bring about changes in the energy landscape in their state, as different leaders have different priorities. These priorities and objectives play an instrumental role in driving legislative policy agendas.

In recent years, the energy segment of gubernatorial/mayoral candidate platforms has centered on ensuring a clean energy future, including decarbonization of the power sector and increased utilization of renewable resources. Another frontline issue has been grid modernization, including the deployment of distributed energy resources and protecting the nation's energy system and infrastructure from cyberthreats.

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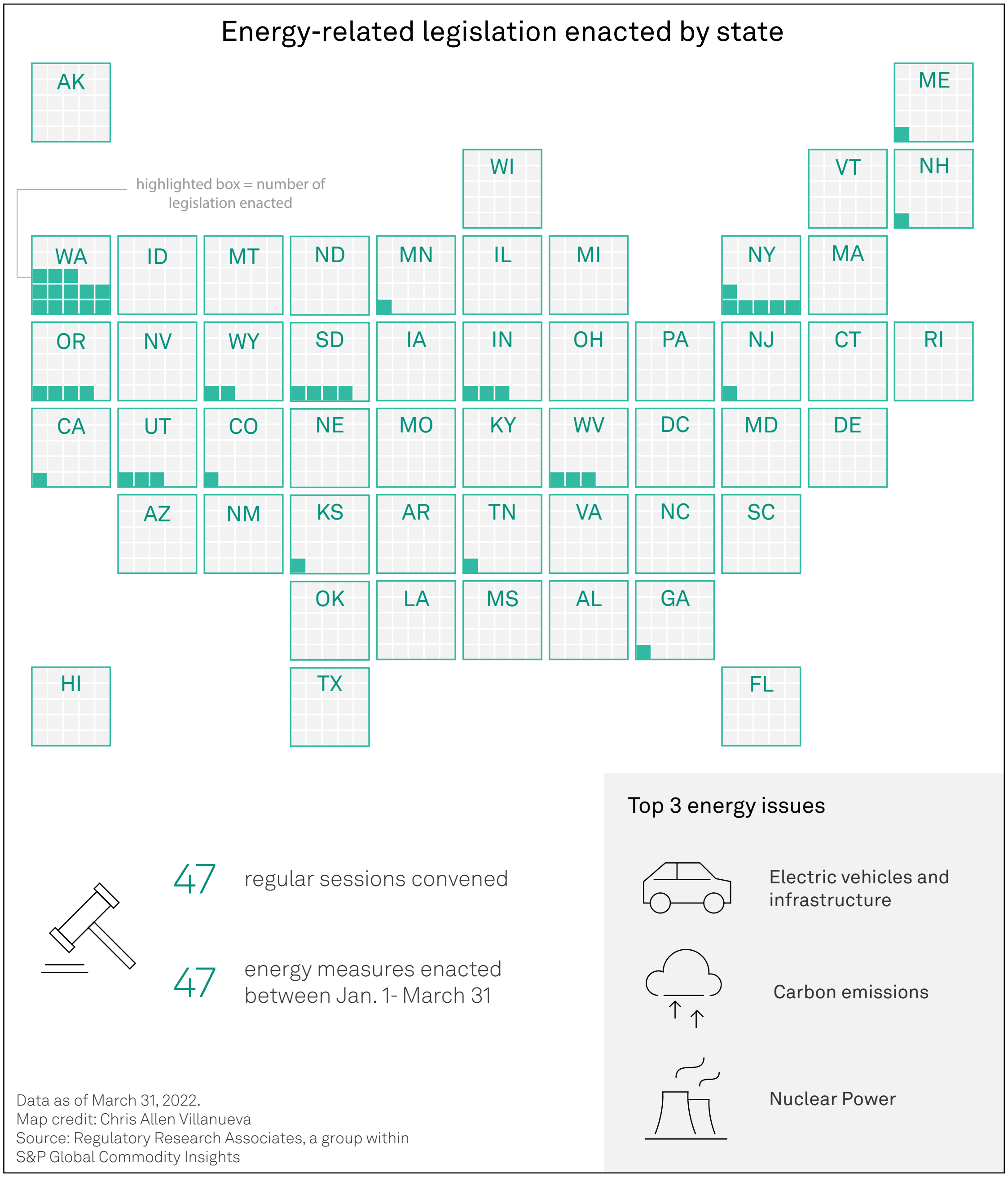


Similar issues have been the focus of recent legislative sessions. Approximately 47 energy-related measures were enacted in the first quarter of 2022 by state legislatures across the U.S. Bills relating to electric vehicles, carbon emissions and nuclear power plants topped the list of the most commonly enacted energy-related measures across 17 states. Additional bills dealt with COVID-19 relief and utility service disconnection moratoriums, community solar, renewable fuel and building decarbonization.

Energy transition-related uncertainty and cost recovery continues to impact regulatory risk

Unlike other Clean Air Act emission reduction mandates that impacted the energy utility sector, the ability of the U.S. Environmental Protection Agency, or EPA, to set policy on carbon emissions reductions has been shrouded in controversy — from the challenges to and ultimate demise of the Obama administration's Clean Power Plan to the Trump administration's Affordable Clean Energy rule that was ultimately overturned by the U.S. District Court.

Now the industry is on pins and needles waiting simultaneously for the Biden administration's EPA to release its version of a carbon emissions rule and a determination from the U.S. Supreme Court regarding whether the EPA even has the authority to issue such regulations.

Even though many argue that the court had no standing to hear the case because there is no rule currently in place that a plaintiff can claim is causing harm, the Supreme Court heard arguments on the issues on Feb. 28. A decision is not expected until June.

The ongoing controversy raises many questions. Among them — whether Congress must enact another amendment to the Clean Air Act to move forward with new carbon emissions rules that have the potential to "restructure the industry" as the plaintiffs claim.

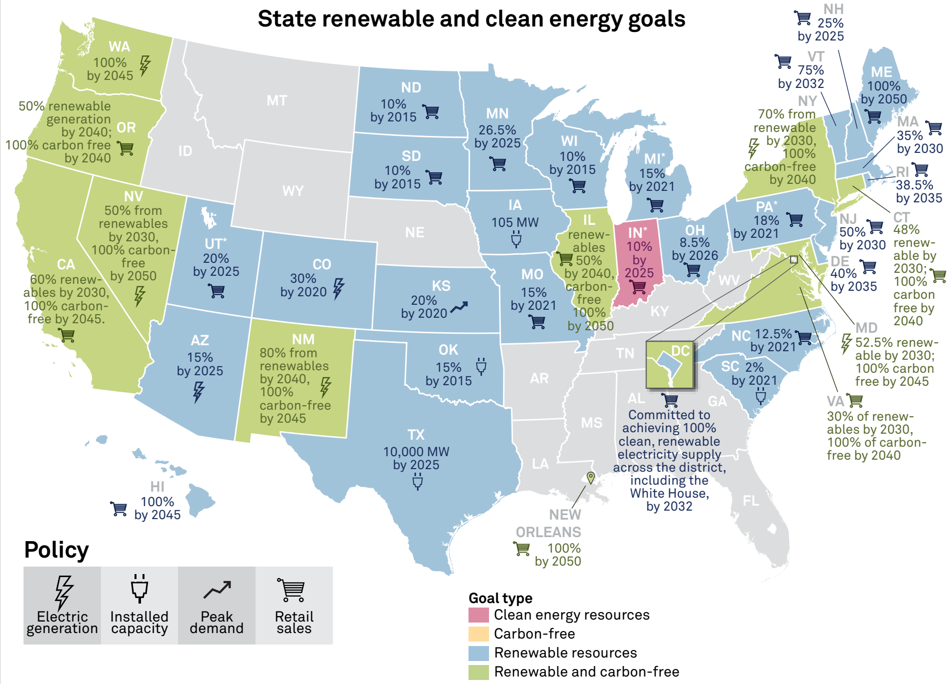
If the court rules that the EPA does not have the authority under current law to promulgate carbon reduction rules, it seems unlikely in the current political climate that a cohesive plan could make it through both chambers of the legislature in a form that the President would sign.

The outcome could also have broader implications for the enforcement and rulemaking powers of the EPA and other federal agencies.

For the time being, without a federal policy that lays out a clear path, these issues will continue to be addressed mainly at the state level.

Currently, all but 13 of the 53 state-level jurisdictions RRA follows have some type of renewable or clean energy standard in place. There are differences in terms of the timeline and ultimate end-state to be achieved, and also what qualifies as a renewable or clean energy resource.

State renewable and clean energy goals



As of May 19, 2022.
* Includes nonrenewable alternative resources.
Indiana, Kansas, North Dakota, Oklahoma, South Carolina, South Dakota and Utah have renewable portfolio goals instead of standards.
In Minnesota, Xcel Energy is required to generate 31.5% of its retail sales from renewable resources by 2020.
In Colorado, for utilities serving more than 500,000 customers, a clean energy goal of 100% of retail sales by 2050 is in place.
Map credit: Joe Felizadio
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

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However, even if there is consensus regarding emission reduction targets and timelines, transitioning among types of resources presents challenges that need to be addressed.

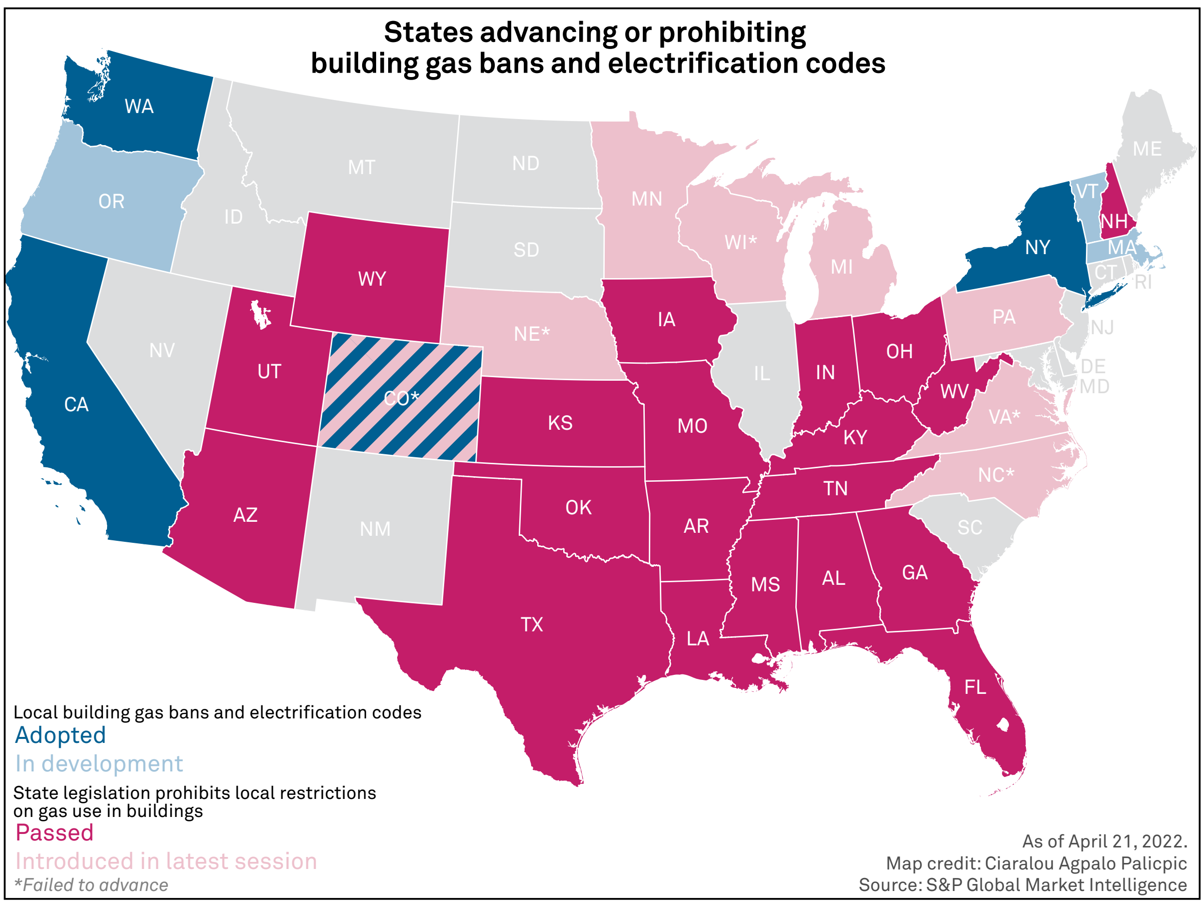
- Integration of new resources into the grid and ensuring the appropriate infrastructure is in place to support new resources and deployment of new technology.
- Regulators must address cost shifting among not only customer classes, but also among customers within the same class.
- Maintaining universal access to service, as well as ensuring that all customers have access to the benefits the transition is intended to provide.
- And, last but not least, addressing stranded costs in order to ensure that the utilities retain adequate access to capital.

In the early stages of the transition, targeted emission declines were achieved primarily by substituting coal generation with natural gas generation, leading to “stranded costs” when coal plants are retired prior to the end of their useful lives.

As state renewable energy and carbon emission reduction requirements have expanded, coal plants that had been retrofitted to reduce emissions and natural gas facilities face the risk of becoming stranded.

Shifts in the location of the resource mix due to the penetration of renewables are changing transmission needs and could ultimately lead to stranded investments in these assets.

Decentralized configurations, such as distributed generation and microgrids, present potential threats to the utilities’ ability to recover investments in fixed distribution system assets and may lead to stranded costs in this segment of the industry.



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The push to implement advanced metering infrastructure to accommodate new resources and market frameworks has, in some instances, led to stranded costs in the form of legacy meters that were not fully depreciated or will not yet be fully recovered when replaced.

Localized initiatives to ban natural gas in new construction within certain states are raising the specter of stranded assets for natural gas LDCs.

For regulated utilities, addressing stranded costs falls to regulators, and it is generally agreed that under the "regulatory compact," the utility should be able to recover the costs that have become stranded because of a change in public policy that occurred after the underlying assets were constructed and in operation.

What is the regulatory compact?
Derives from the "Takings Clause" of the Fifth Amendment to the U.S. Constitution.
The utility is granted a monopoly to provide service in a specific geographic area in exchange for being regulated by a government agency.
The utility agrees to provide safe, reliable service at just and reasonable rates, to all customers in the service area, while the regulator agrees to provide the utility an opportunity to earn a fair return for its investors.

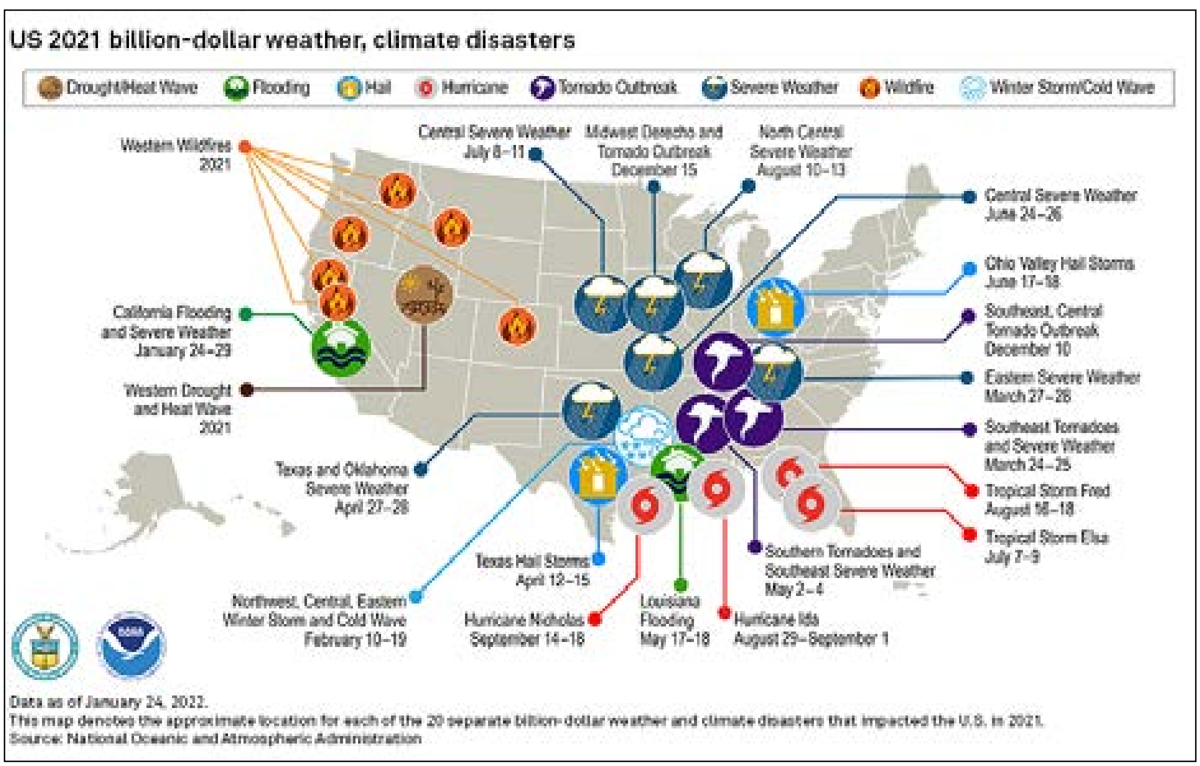
State regulators and policymakers are using various options to address stranded costs.

The use of accelerated depreciation, creation of regulatory assets, offsetting stranded cost-related regulatory assets with existing regulatory liabilities and securitization are among the strategies being employed. All of these strategies have different implications for utility rates and the financial performance of the state's utilities.

The need to address this issue is further complicated by the uncertain economic environment, rising inflation and interest rates and the level of capital spending required to meet the twin goals of improving reliability and transitioning to new power sources.

Storm cost recovery

Another issue arising with increasing frequency across the sector is the treatment to be accorded extraordinary storm-related costs. Costs associated with storm restoration activities are among the items that account for expanding capital spending plans and in turn, rising utility rates.



Most utilities have provisions in their base rates for "normalized" storm costs; these are generally estimates based on historical averages for varying time frames. However, in recent years, the instances where actual storm-related costs have significantly exceeded the baselines reflected in rates have become more numerous.

Certain states have allowed utilities to include in rates an incremental amount to fund a storm reserve that the utilities can then tap for costs that exceed the baseline levels.

In others, the utilities — through either incident-specific accounting orders or routine commission policy — are permitted to defer "extraordinary" storm costs for future recovery. Recovery is generally addressed in rate cases and is usually authorized over a relatively short period — five to seven years. The utilities are usually permitted to earn a return on the unamortized balance.

In cases where the amounts to be recovered are particularly large, the utilities may be permitted to use securitization to finance the deferred balances and even to replenish storm cost reserves.

States like Florida, Louisiana, Mississippi and Texas, as it pertains to electric utilities, have had legislation in place for many years that allows the utilities to use securitization to finance storm-related deferrals. But in the wake of recent major storms, legislatures in Kansas, North Carolina, Missouri, Oklahoma and Texas have enacted new statutes introducing or expanding the use of this financing tool.

Coronavirus/COVID-19

With utility disconnection moratoriums implemented in the wake of the COVID-19 pandemic coming to an end for most, if not all, customers across the country, issues related to the recovery of the related costs are beginning to be addressed in rate cases.

Thus far, recovery has not been particularly contentious. Where the issue has been addressed, commissions have generally allowed recovery of any related deferrals to occur for a few years, with varying treatment with respect to allowing a return on the unamortized balance. However, in some instances, regulators have directed the utilities to continue to defer some, if not all, of their COVID-19-related costs.

Like energy transition stranded costs and extraordinary storm costs, recovery of COVID-19-related deferrals is putting upward pressure on rates at a time when regulators are grappling with providing utilities rate recognition for robust utility capital spending plans.

Russian invasion of Ukraine

Russia's invasion of Ukraine and the ongoing conflict have certain indirect impacts for U.S. utilities and regulators. For the most part, the implications are generally in the category of increasing costs at a time when utility prices are trending upward due to other macroeconomic trends and industry-specific issues.

With regard to rising fuel costs, S&P Global Ratings has raised its 2022-2023 price assumptions for Henry Hub and AECO. The just-announced ban on Russian energy product imports could cause additional fuel price volatility for U.S. utilities and merchant providers. In addition, generation providers that own nuclear facilities have expressed concern that the U.S. economic sanctions on Russia may ultimately include a ban on uranium imports.

Supply chain disruptions, which have been creating challenges for utilities during the COVID-19 pandemic, are expected to intensify as the conflict wears on, causing uncertainty regarding the prices of metals that are inputs for electronic devices, solar panels, smart grid components and steel production.

While state-level governments are limited in how they can formally sanction Russia, many governors issued statements, executive orders or letters condemning the actions of the Russian military. Half of the U.S. governors called on President Joe Biden to focus on American energy independence. Among the actions proposed, the governors urged Congress and federal agencies to increase U.S. domestic oil and gas production.

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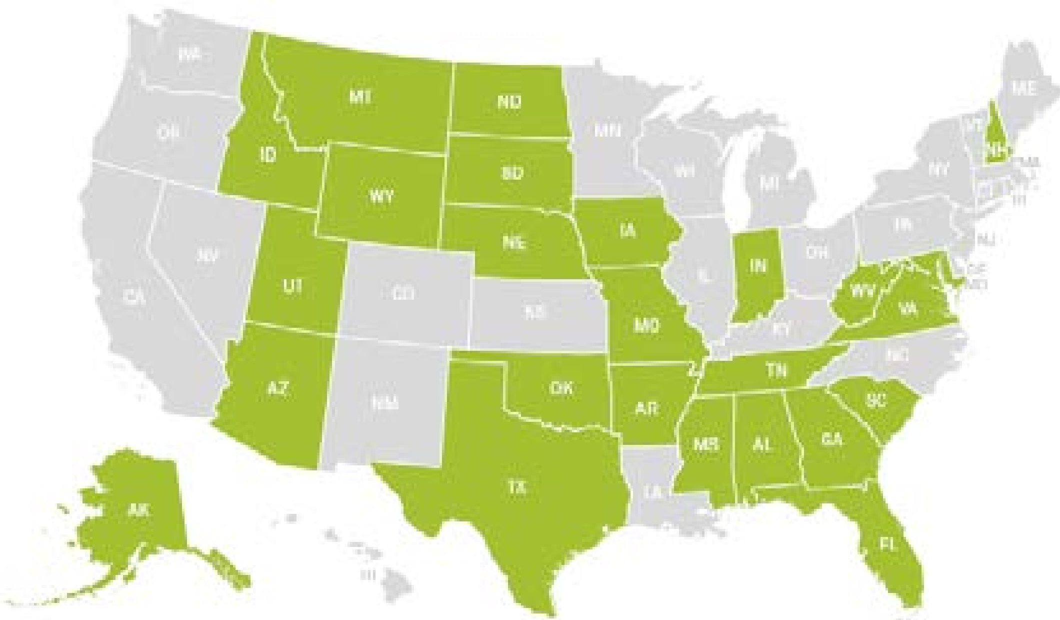
Another focus is cybersecurity. In February, the U.S. Department of Homeland Security's Cybersecurity and Infrastructure Agency issued a "Shields Up" alert for all U.S. corporations. The industry has been working to beef up security, as it pertains to incursions targeted at financial information. Still, certain experts have expressed concern that physical security may be another matter, explaining that larger vertically integrated utilities may be better prepared to withstand an attempted incursion while smaller competitive providers may not be.

Governors calling for American energy independence

25 of the nation's 28 Republican governors issued a statement urging President Biden to restore American energy independence in light of Russia's invasion of Ukraine.



Data compiled on March 15, 2022.
Source: Idaho Office of the Governor

RRA's rankings process

RRA maintains three principal rating categories, Above Average, Average and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint and Below Average indicating a less constructive, higher-risk regulatory climate. Within each principal rating categories, the numbers 1, 2 and 3 indicate relative position.

The designation 1 indicates a stronger or more constructive rating from an investor viewpoint; 2, a midrange rating; and 3, a less constructive rating.

Hence, if you were to assign numeric values to each of the nine resulting categories, with a "1" being the most constructive from an investor viewpoint and a "9" being the least constructive from an investor viewpoint, then Above Average/1 would be a "1" and Below Average/3 would be a "9."

RRA State Regulatory Evaluations*

Energy

Above Average 1	Average 1	Below Average 1
Alabama	Arkansas	Alaska
	Colorado	Connecticut
	Indiana	Kansas
	Nebraska	Montana
	North Dakota	New Jersey
	Texas — RRC	
	Virginia	
Above Average 2	**Average 2**	**Below Average 2**
Florida	California	Dist. of Columbia
Georgia	Hawaii	New Mexico
Pennsylvania	Idaho	West Virginia
Wisconsin	Illinois	
	Kentucky	
	Louisiana — PSC	
	Massachusetts	
	Minnesota	
	Nevada	
	New York	
	New Hampshire	
	Oklahoma	
	Oregon	
	Rhode Island	
	South Dakota	
	Utah	
	Wyoming	
Above Average 3	**Average 3**	**Below Average 3**
Iowa	Delaware	Arizona
Michigan	Louisiana — NOCC	
Mississippi	Maine	
North Carolina	Maryland	
Tennessee	Missouri	
	Ohio	
	South Carolina	
	Texas — PUC	
	Vermont	
	Washington	

Data compiled as of May 27, 2022.
* Within a given subcategory, states are listed in alphabetical order, not by relative ranking.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

Methodology

While numerical scores are employed, the rankings are subjective and are intended to be comparative in nature.

The rankings are designed to reflect the interest of both equity and fixed-income investors across more than 30+ individual metrics. The individual scores are assigned based on the covering analysts' subjective judgement.

The scores are then aggregated to create a single score for each state, with certain categories weighted more heavily than others.

The states are then ranked from lowest to highest and distributed among the nine categories to create an approximate normal distribution.

This distribution is then reviewed by the team, and individual state rankings may be adjusted based on the covering analysts' recommendations, subject to review by a designated panel of senior analysts.

The variables that RRA considers in determining each state's ranking are largely the broad issues detailed in state Commission Profiles on the S&P Capital IQ Pro platform and those that arise in the context of rate cases, generic policy proceedings, legislation and gubernatorial directives.

RRA's articles and reports on these issues are accessible through the S&P Capital IQ Pro platform, as are the aforementioned jurisdictional commission profiles and RRA's database of major investor-owned utility rate case decisions going back to 1980.

As implied by the above discussion, the rankings not only reflect the decisions rendered by the state regulatory commission, but also reflect the impact of the actions taken by the governor, the legislature, the courts and consumer advocacy groups. The policies examined pertain largely to rate cases and the ratemaking process, but issues such as industry restructuring, corporate governance, treatment of proposed mergers and those related to the ongoing energy transition are also considered.

In the charts within this report that depict the rankings by category, the jurisdictions in each category are listed in alphabetical order rather than by relative position within the category.

Since the rankings are meant to be comparative in nature, RRA endeavors to maintain an approximately "normal" distribution with the majority of the ranking in the three average categories and the remainder split roughly evenly between the Above Average and Below Average categories.

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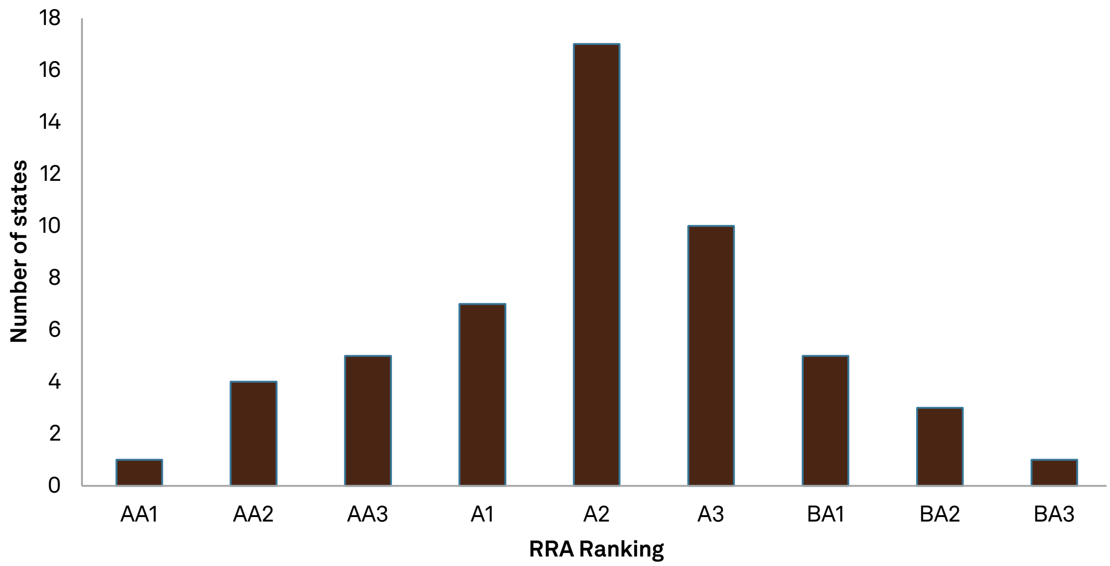
State regulatory rankings distribution*



Data compiled May 27, 2022.
* Graph is based on rankings of regulatory climate for energy utilities only.
AA = Above Average; A = Average; BA = Below Average
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

Overview of issues examined

The summaries below provide an overview of the variables RRA looks at, including a brief discussion of how each can impact the ranking of a given regulatory environment.

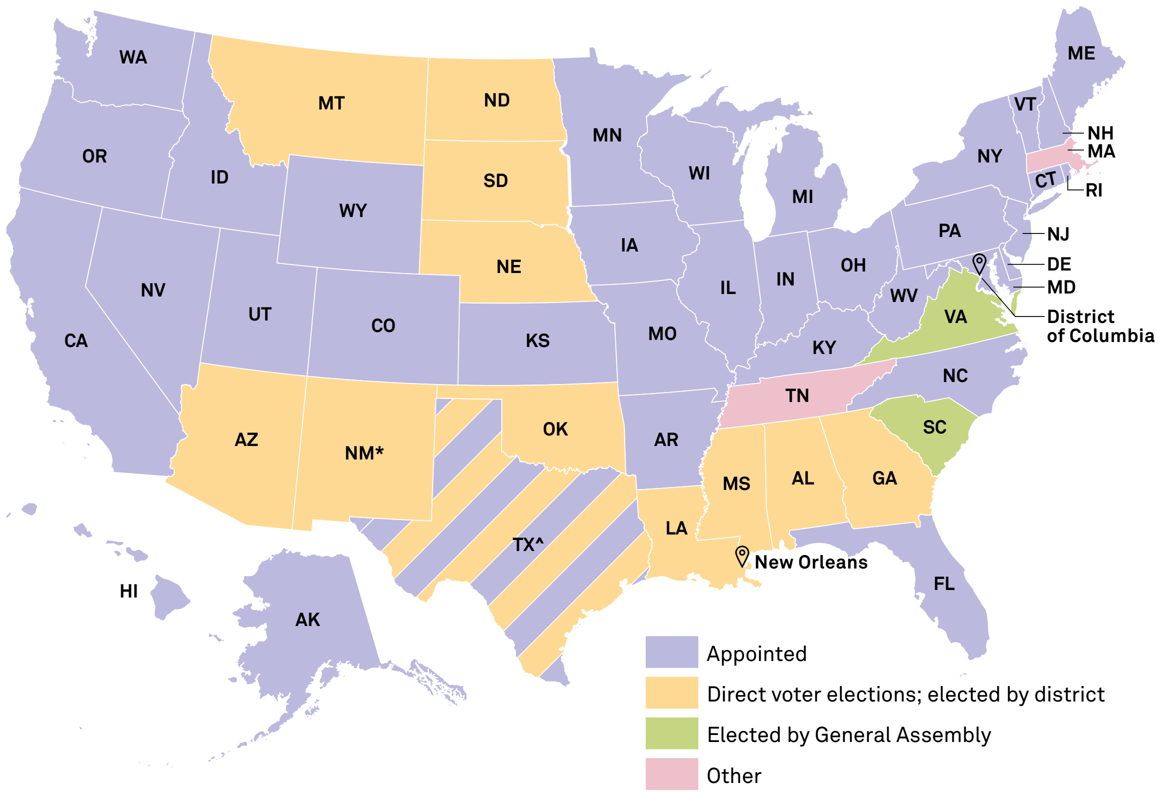
Governor/Mayor — The impact the governor, or the mayor in the District of Columbia, may have depends largely on the individual; the issue of elected versus appointed commissioners is evaluated separately.

RRA takes no view on which political party is the more or less constructive option. However, attributes of the governor or the gubernatorial election process that can move the needle here are: whether energy issues were a topic of debate in recent elections and what the tone/topic of the debate was; whether the governor seeks to become involved in the regulatory process; and the type of influence the governor is seeking to exert.

Commissioner selection process/membership — RRA looks at how commissioners are selected in each state. All else being equal, RRA attributes a greater level of investor risk to states in which commissioners are elected rather than appointed. Generally, energy regulatory issues are less politicized when they are not subject to debate in the context of an election.

Realistically, a commissioner candidate who indicates support for the utilities and their shareholders or appears to be amenable to rate increases is not likely to be popular with the voting public. In addition, there might not be specific experience requirements to run for commissioner, so, a newly elected candidate may have a steeper learning curve with respect to utility regulatory and financial issues, which could make discerning the decisions that individual might make more difficult and could increase uncertainty.

Commissioner selection methods in the US



Data as of May 27, 2022
* Beginning in 2023, members of the New Mexico Public Regulation Commission will be appointed by the governor.
^ The Public Utility Commission of Texas members are appointed by the governor, while members of the Railroad Commission of Texas are elected in statewide elections.
Map credit: Augusto Justiniano Jr.
Source: Regulatory Research Associates, a group within S&P Commodity Insights

However, there have been some notable instances in which energy issues played a key role in gubernatorial/senatorial elections in states where commissioners are appointed, with detrimental consequences for the utilities.

In addition, RRA looks at the commissioners themselves and their backgrounds. Experience in economics and finance and/or energy issues is generally seen as a positive sign. Previous employment by the commission or a consumer advocacy group is sometimes viewed as a negative indicator.

In some instances, new commissioners have very little experience or exposure to utility issues, and in some respects, these individuals represent the highest level of risk, simply because there is no way to foresee what they will do or how long it will take them to "get up to speed." Controversy or "scandal" surrounding an individual and/or the potential for a conflict of interest are also red flags.

Similarly, a high rate of turnover or the tendency to allow vacancies to stand unfilled for a long period of time add to the level of regulatory risk in RRA's view.

Commission staff/consumer interest — Most commissions have a staff that participates in rate proceedings. In some jurisdictions, the staff has a responsibility to represent the consumer interest and in others, the staff's statutory role is less defined. In addition, there may or may not be additional state-level organizations that are charged with representing the interests of a certain class or classes of customers, such as the attorney general or the consumer advocate, private consortia or lobbying groups that represent certain customer groups and/or large-volume commercial and industrial customers that intervene directly in rate cases.

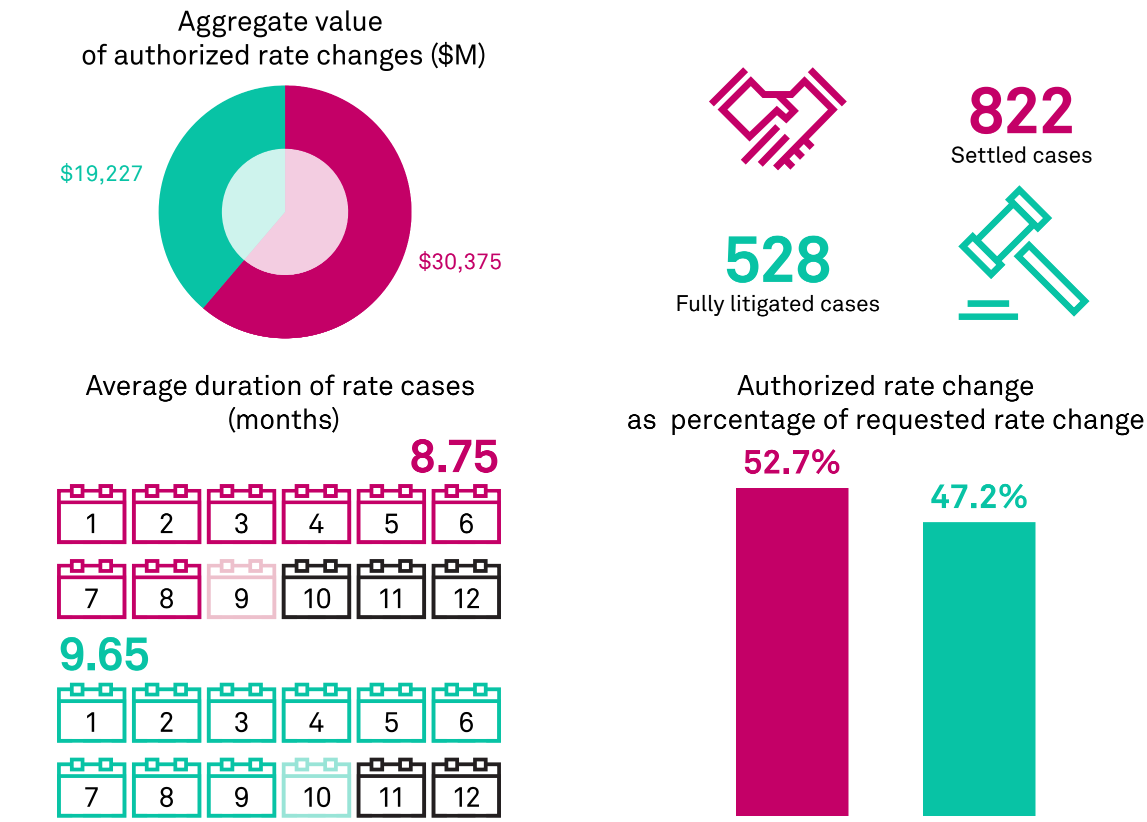
Generally speaking, the greater the number of consumer intervenors, the greater the level of uncertainty for investors, as in most instances the only party representing investors' interests is the company. The level of risk for investors also depends on the caliber and influence of the intervening parties and the level of contentiousness in the rate case process. Even though a commission may not adopt an extreme position taken by an intervenor, the inclusion of an extreme position in the record for the case widens the range of possible outcomes, reducing certainty and increasing the risk of a negative outcome for investors. RRA's opinion on these issues is largely based on experience and observations.

Settlements — An increasing number of cases in recent years have been resolved by settlements rather than through a fully litigated process. There are often clear incentives for utilities and entities with vested interests in the sector to embrace compromise. Utilities often obtain settlement benefits in the form of key utility policy objectives and more timely and favorable rate case outcomes than would otherwise be achievable.

In some instances, the settlement sets out all of the typical rate case parameters, such as rate of return and rate base, but many are resolved by "black-box" settlements, which are filed when the parties are able to settle all, or nearly all, of their differences in the proceeding, but none of the parties wants to disclose the final outcome on a given issue because they want to avoid establishing a precedent.

Or, during settlement discussions, each party may have contemplated a certain revenue change amount as acceptable and may have performed calculations regarding the rate base and rate-of-return parameters behind their revenue requirement positions. However, different values for these inputs could be used in varying combinations to determine the same revenue requirement.

Settled vs. fully litigated rate proceedings by the numbers, 2007-2021



Data compiled Feb. 17, 2022.
Excludes limited issue rider proceedings.
Credit: Saddat Sarfraz
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

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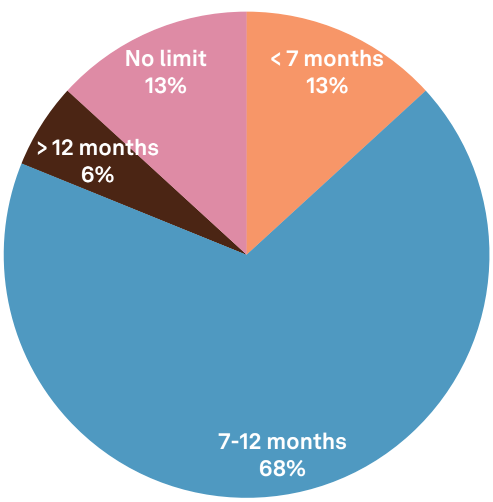
In most instances, the ability of the parties to reach agreement without having to go through a fully litigated proceeding is considered constructive, particularly since it reduces the likelihood of court review after the fact. However, RRA also endeavors to ascertain whether the settlements arise because of a truly collaborative approach among the parties, or if they result from concern by the companies that the commissioners' views may be even less favorable than the intervenors', or that the intervenors will take a more extreme position in a litigated framework than in a closed-door settlement negotiation, resulting in a less constructive outcome.

In some instances, the parties may agree on only certain issues and will execute a partial settlement on those issues, while the remaining issues in the case will be litigated. In the years 2007 through 2021, RRA tracked 1,350 electric and gas utility base rate cases across the U.S. Of these proceedings, 822 were deemed to be "settled" — indicating that issues accounting for the bulk of the revenue requirements in these cases were ultimately settled.

Rate case timing — For each state commission, RRA considers whether there is a set time frame within which a rate case must be decided, the length of any such statutory time frame and the degree to which the commission adheres to that time frame.

About two-thirds of state commissions nationwide have a rule or statute that requires a rate case to be decided within seven to 12 months of filing.

Rate case time frame



Data compiled as of May 27, 2022.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

RRA generally views a set time frame as preferable, as it provides a degree of certainty as to when any new revenue may begin to be collected.

Shorter time frames may apply for limited-issue proceedings, but there are very few states where a rate case will take less than seven months to be decided.

In addition, a shorter time frame for a decision generally reduces the likelihood that the actual conditions during the first year the new rates will be in effect will vary markedly from the test period utilized to set new rates, thus keeping regulatory lag to a minimum.

Interim procedures — The ability to implement all or a portion of a proposed rate increase on an interim basis prior to a final decision in a rate case is viewed as constructive. However, should the commission approve a rate change that is markedly below the rates implemented on an interim basis, the utility would be required to refund any related over-collections, generally with interest.

In some instances, commission approval is required prior to the implementation of an interim increase and may or may not be easy to obtain, while in others, state law or commission rules permit the companies to implement interim rate increases as a matter of procedure. In some instances, the commission may establish a date prior to the final decision in the case that will be the effective date of the new rates. In these instances, the company may be permitted to recoup any revenue that was not collected between the effective date and the decision date.

Rate base — A commission's policies regarding rate base can also impact the ability of a utility to earn its authorized ROE. These policies are often outlined in state statutes, and the commission usually does not have much latitude with respect to these overall policies.

With regard to rate base, commissions are about evenly split between those that employ a year-end, or terminal, valuation and those that utilize an average valuation, with one using a "date certain." In some instances, the commission may employ a different rate base valuation method depending on the utility type or case type — general rate case or limited-issue proceeding — or based on the test year selected by the company.

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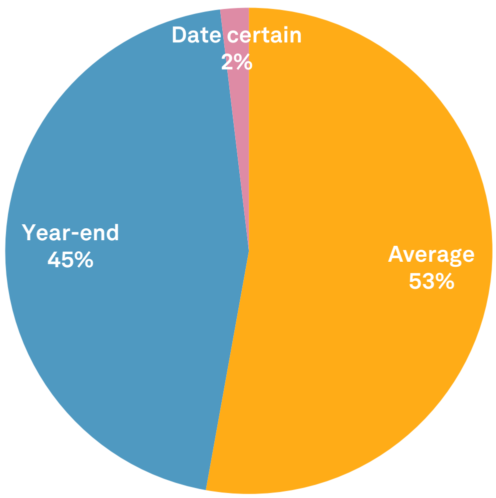
In general, assuming rate bases are rising, i.e., new investment is outpacing depreciation, a year-end valuation is preferable from an investor viewpoint.

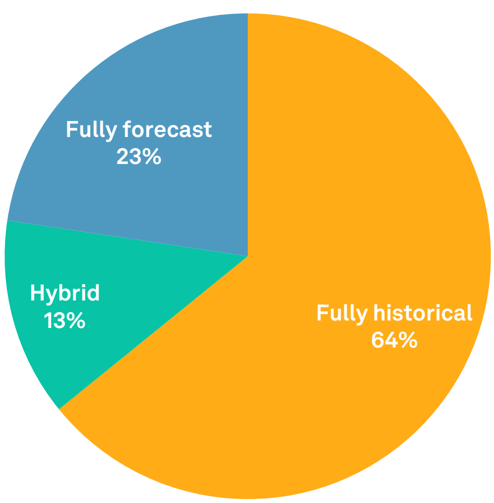
This again relates to how well the parameters used to set rates reflect actual conditions that will exist during the rate-effective period; hence, the more recent the valuation, the more likely it is to approximate the actual level of rate base being employed to serve customers once the new rates are placed into effect.

Rate base valuation method



Data compiled as of May 27, 2022.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

Rate case test year



Data compiled as of May 27, 2022.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

Some commissions permit post-test-year adjustments to rate base for "known and measurable" items, and in general, this practice is beneficial to the utilities in periods where operating costs are rising and the company is making significant investments in infrastructure and other capital items.

However, the rules with respect to what constitutes a known and measurable adjustment are not always specific, and there can be a good deal of controversy about what does and does not pass muster.

Another key consideration is whether state law and/or the commission generally permits the inclusion in rate base of construction work in progress, or CWIP, for a cash return. CWIP represents assets that are not yet, but ultimately will be, operational in serving customers.

Investors generally view inclusion of CWIP in rate base for a cash return as constructive, since it helps to maintain cash flow metrics during a large construction cycle. Alternatively, the utilities accrue allowance for funds used during construction, which is essentially booking a return on the construction investment as a regulatory asset that is recoverable from ratepayers once the project in question becomes operational.

While this method bolsters earnings, it does not augment cash flow and does not support credit metrics. For a more in-depth look at rate base issues, refer to the RRA report entitled Rate base: How would you rate your knowledge of this utility industry fundamental?

Test period — With regard to test periods, there are a number of different practices employed, with the extremes being fully forecast at the time of filing, which is considered to be most constructive, on the one hand, and fully historical at the time of filing, considered to be least constructive, on the other.

Some states utilize a combination of the two, in which a utility is permitted to file a rate case based on data that is fully or partially forecast at the time of filing and is later updated to reflect actual data that becomes known during the course of the proceeding. In these cases, the test year is historical by the time a decision is ultimately rendered due to which regulatory lag remains a problem.

In some states, the commission uses a historical test year for single-year base rate cases, but forward-looking test years for multiyear rate cases, alternative regulation plans and/or adjustment clauses.

Almost two-thirds of the 53 jurisdictions covered by RRA utilize a test year that is historical at the time of filing. As with rate base valuation, in some states, commissions use different test period types for different types of proceedings or utilities.

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Many of the jurisdictions allow for known and measurable adjustments to the test year, but there is considerable variability regarding how far beyond the end of the test year these adjustments may go, and statutes governing the definition of known and measurable can be ambiguous. Consequently, there can be wide disagreement among the rate case parties as to which adjustments qualify.

Return on equity — ROE is perhaps the single most litigated issue in any rate case. There are two ROE-related issues that RRA considers when evaluating an individual rate case and the overall regulatory environment: (1) how the authorized ROE(s) compares to the average of returns authorized for energy utilities nationwide over the 12 months or so immediately preceding the decision and (2) whether the company has been accorded a reasonable opportunity to earn the authorized return in the first year of the new rates.

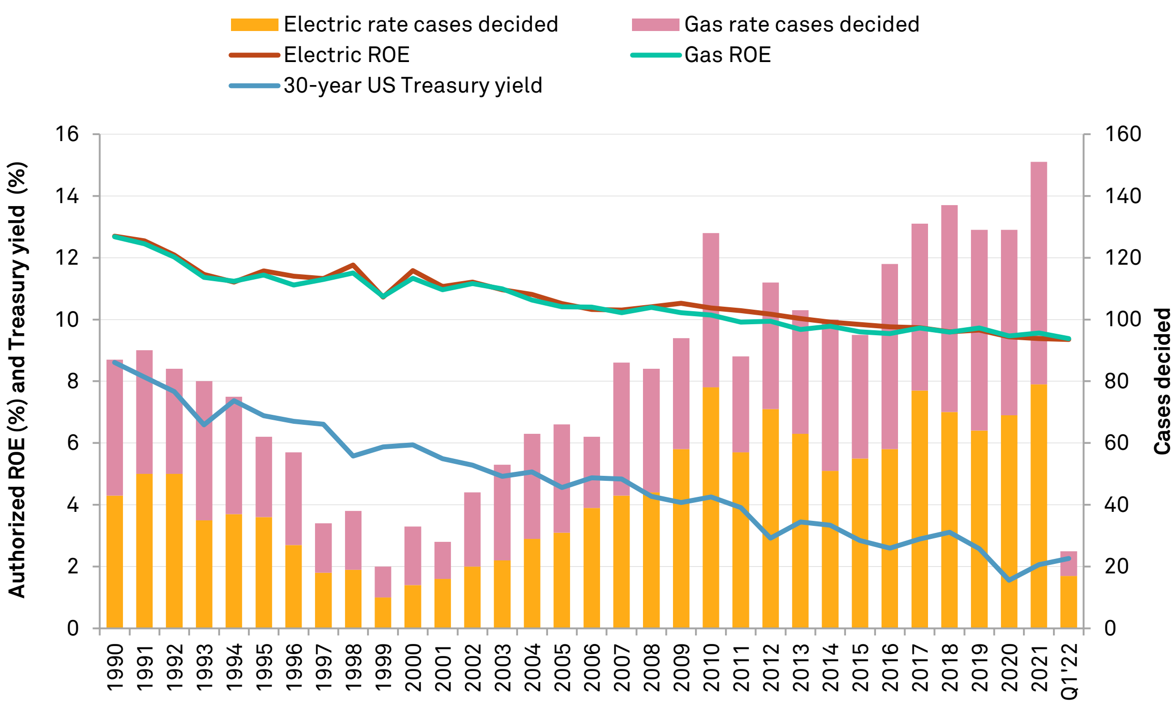
In establishing rankings, RRA looks at the ROEs historically authorized utilities in a given state and compares them to utility industry averages, as calculated in RRA's Major Rate Case Decisions Quarterly Update reports. When referring to these "averages," RRA means the average ROE approved in cases decided in a particular year; returns carried over from prior years are not included in the averages.

Interest rates have been a key factor driving authorized ROEs downward, but commission determinations that various alternative or innovative ratemaking mechanisms have reduced risk for the companies and their investors across the board have played a role as well.

Authorized ROEs overall have been declining steadily since 1980, falling below 10% for the first time in 2011 for gas utilities and 2014 for electric utilities, and remaining below that benchmark since.

Between 2015 and 2018, RRA observed a modest recovery in authorized ROEs, as the U.S. Federal Reserve unwound its quantitative easing policy and implemented a series of gradual interest rate increases. As has typically been the case, authorized ROEs lagged interest rate trends somewhat and so continued to rise modestly during 2019 even though the Fed lowered interest rates to combat a slowing economy.

Average electric and gas authorized ROEs and total number of rate cases decided



Data compiled April 25, 2022.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; U.S. Department of the Treasury

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In 2020, with the U.S. economy challenged by fallout from the COVID-19 pandemic, the average of the equity returns authorized for both electric and gas utilities nationwide fell to their lowest levels then on record. In 2021, the average gas ROE rebounded slightly to 9.56%, versus the 9.46% observed in 2020, but still near historical lows. The average electric ROE fell to an all-time low of 9.38% versus the 9.44% average for cases decided in 2020.

The need to recognize the planned capital spending and other costs associated with energy transition activities, rising interest rates, inflation and the political distaste for approving rate increases in an uncertain economic environment has resulted in shrinking “headroom” in utility rates.

More frequent severe weather events, supply chain disruptions, the potential for increases in federal corporate tax rates and inflationary pressures, represent significant unplanned costs on the system that will only serve to increase the pressure on regulators to reduce authorized ROEs.

In addition, consumer advocacy organizations continue to argue that lower returns on equity are warranted because of risk-reducing factors, such as limited-issue riders, decoupling mechanisms, alternative regulation constructs and changes to basic rate design.

This presents a stark contrast to views held by both fixed-income and equity investors that utilities are becoming increasingly risky because of the very factors that are leading regulators to approve lower ROEs.

Intuitively, authorized ROEs that meet or exceed the prevailing averages at the time established are viewed as more constructive than those that fall short of these averages.

However, in the context of a rate case, a utility may be authorized a relatively high ROE, but factors such as capital structure changes, the age or “staleness” of the test period, rate base and expense disallowances, the manner in which the commission chooses to calculate test year revenue and other adjustments may render it unlikely that the company will earn the authorized return on a financial basis.

Hence, the overall decision may be restrictive from an investor viewpoint, even though the authorized ROE is equal to or above the average.

Even if a utility is accorded a “reasonable opportunity” to earn its authorized ROE, there is no guarantee that the utility will do so. The revenue requirement and ROE established in a rate case are targets that the commission believes the established rates will allow the utility to achieve on a prospective basis.

Various factors such as weather, management efficiency, unexpected events, demographic shifts, fluctuations in economic activity and customer participation in energy conservation programs may cause revenue and earnings to deviate from expectations.

With respect to capital structure, most commissions utilize the company’s actual capital structure at a given point in time, but in some instances, the commission may rely on a hypothetical capital structure that represents a mix of debt and equity that the commission views as more reasonable or economically efficient. If a commission uses a capital structure that is more highly leveraged than the company’s actual structure, this will lower the authorized overall return and the revenue requirement ultimately approved and may render it more difficult for the company to earn the authorized return on its actual equity.

Accounting — RRA looks at whether a state commission has permitted unique or innovative accounting practices designed to bolster earnings. Such treatment may be approved in response to extraordinary events, such as storms, or for volatile expenses, such as pension costs. Generally, such treatment involves deferral of expenditures that exceed the level of such costs reflected in base rates. In some instances, the commission may approve an accounting adjustment to temporarily bolster certain financial metrics during the construction of new generation capacity.

From time to time, commissions have approved frameworks under which companies were permitted to, at their own discretion, adjust depreciation to mitigate under-earnings or eliminate an overearnings situation without reducing rates. These types of practices are generally considered to be constructive from an investor viewpoint.

Federal tax law changes enacted in 2017 and effective in 2018, particularly the reduction in the corporate federal income tax rate to 21% from 35%, had sweeping impacts on utilities, with a flurry of ratemaking activity during 2018 and 2019.

For most of the companies, rates were reduced to reflect the ongoing impact of the lower tax rate; refunds to return to ratepayers related to deferred overcollections are occurring over a relatively short time period, and amortization of the related excess accumulated deferred income tax liabilities is occurring over varying time periods — generally over the lives of the companies' assets for liabilities tied to protected assets and most often five to 10 years for unprotected liabilities. RRA has been monitoring these developments and their impact on credit ratings and investor risk.

The prospect for tax rate changes under the Biden administration that would reverse, at least in part, the 2018 corporate income tax rate reduction raises the level of risk for all companies across the sector.

Another accounting-related issue that RRA has been following over the past more than two years is the treatment that is being accorded costs associated with the COVID-19 pandemic; specifically, whether the commissions approved deferral of the costs, and how recovery of those deferrals is being or is to be addressed. Recovery of these deferrals will place upward pressure on rates and further shrink headroom for increases associated with investments in strategic initiatives.

In the wake of the energy transition movement, increasing number of fossil generation facilities and legacy meters are being retired early. Other types of utility assets may also potentially lead to stranded costs as this transition progresses. RRA is monitoring how states are approaching energy transition and how it impacts the incumbent utilities, as well as stranded cost recovery policies.

In some states, companies have been permitted to accelerate depreciation of certain facilities in order to complete recovery of the investment prior to closure, and in others, the utilities are being permitted to defer the remaining book value at closure as a regulatory asset that is to be recovered over a period of years.

Alternative regulation —RRA generally views as constructive the adoption of alternative regulation plans that are designed to streamline the regulatory process and cost recovery or allow utilities to augment earnings in some way. These plans can be broadly or narrowly focused.

Narrowly focused plans may: allow a company or companies to retain a portion of cost savings relative to a base level of some expense type, e.g., fuel, purchased power, pension cost, etc.; permit a company to retain for shareholders a portion of off-system sales revenues; or provide a company an enhanced ROE for achieving operational performance and/or customer service metrics or for investing in certain types of projects, e.g., demand-side management programs, renewable resources, new traditional plant investment.

Broad-based plans include ROE-based sharing mechanisms, formula-based rates and multiyear rate plans that apply to all cost-of-service issues rather than targeting specific investments or expenses.

The use of plans with somewhat broader scopes, such as ROE-based earnings sharing plans, is, for the most part, considered to be constructive, but it depends upon the level of the ROE benchmarks specified in the plan and whether there is symmetrical sharing of earnings outside the specified range.

Formula-based ratemaking plans generally refer to frameworks where the commission establishes a revenue requirement, including a target ROE, capital structure and rate of return for an initial rate base as part of a traditional cost of service base rate proceeding. Once the initial parameters are set, rates may adjust periodically to reflect changes in expenses, revenue and capital investment. These changes generally occur on an annual basis, and there may be limitations on the percentage change that can be implemented in a given year or period of years.

Others use multiyear rate plans, under which the commission approves a succession of rate changes that are designed to consider anticipated changes in revenues, expenses and rate base. The commission may approve a static authorized ROE, or the plan may provide for adjustments to the ROE during the plan's term. These plans often include true-up mechanisms to ensure that the company makes the investments it has committed to make at the inception of the plan. The plans often include earnings sharing mechanisms and may also include performance-based ratemaking provisions or stay-out provisions preventing a company from filing a successive rate case until a future point in time.

Overview of select alternative regulation plans for US utilities[1]

Formula-based ratemaking	Multiyear rate plans	Earnings sharing	Incentive ROEs	Electric fuel/ Gas costs	Capacity release/Off-system sales
Alabama	California	Alabama	Colorado	Indiana	Colorado
Arkansas	Connecticut	Arkansas	Iowa	Idaho	Delaware
Georgia	Dist. of Columbia	Connecticut	Kansas[2]	Iowa	Florida
Hawaii	Florida	Florida	Mississippi	Illinois	Indiana
Illinois	Georgia	Georgia	Montana[2]	Kansas	Iowa
Louisiana — NOCC	Hawaii	Hawaii	Nevada	Kentucky	Kentucky
Louisiana — PSC	Louisiana — NOCC	Idaho	Ohio	Maryland	Louisiana
Maine	Maine	Iowa	Virginia	Missouri	Massachusetts
Massachusetts	Maryland	Kansas	Washington[2]	Montana	Missouri
Minnesota	Massachusetts	Louisiana — NOCC	Wisconsin	New Jersey	New Jersey
Mississippi	Minnesota	Louisiana — PSC		Oregon	New York
Pennsylvania	New Hampshire	Maine		Tennessee	North Dakota
Tennessee	New York	Massachusetts		Rhode Island	New Jersey
Texas—RRC	Ohio	Mississippi		Utah	Oklahoma
Vermont	Pennsylvania[2]	Nevada		Vermont	Pennsylvania
	Rhode Island	New Mexico		Virginia	Rhode Island
	South Carolina	New York		Wyoming	South Dakota
	Utah	Oklahoma			Tennessee
	Vermont	Oregon			Texas — PUC
	Washington[2]	Rhode Island			Texas — RRC
	Wisconsin	South Dakota			Utah
		Vermont			
		Virginia			
		Washington			
		Wisconsin			

Data compiled as of May 27, 2022.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility (ies) Commission; RRC = Railroad Commission.
[1] Mechanism in place for at least one utility in the jurisdiction. This list is not intended to be comprehensive.
[2] Specifically permitted by rule, law or commission order; no mechanism currently in place.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

Court actions — This aspect of state regulation is particularly difficult to evaluate. Common sense would dictate that a court action that overturns restrictive commission rulings is a positive. However, the tendency for commission rulings to come before the courts and for extensive and sometimes protracted litigation as appeals go through several layers of court review may add an untenable degree of uncertainty to the regulatory process. Also, similar to commissioners, RRA looks at whether judges are appointed or elected, as political considerations are more likely to influence elected jurists.

Legislation — While RRA's Commission Profiles provide statistics regarding the makeup of each state legislature, RRA has not found a specific correlation between the quality of energy legislation enacted and the political party controlling the legislature. Of course, in a situation where the governor and legislature are of the same political party, generally speaking, it is easier for the governor to implement key policy initiatives, which may or may not be focused on energy issues.

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Key considerations with respect to legislation include how proscriptive newly enacted laws are; whether the bill is clear or ambiguous and open to varied interpretations; whether it balances ratepayer and shareholder interests rather than merely "protecting" the consumer; and whether the legislation takes a long-term view or is a "knee-jerk" reaction to a specific set of circumstances.

Legislative activity impacting utility regulatory issues has been robust in recent years, as state policymakers, utilities and industry stakeholders seek to address "disruptors" that challenge the traditional regulatory framework. RRA follows these developments closely with an eye toward assessing whether the states are taking a balanced, sustainable approach and how legacy utility providers will be affected by the policies being adopted.

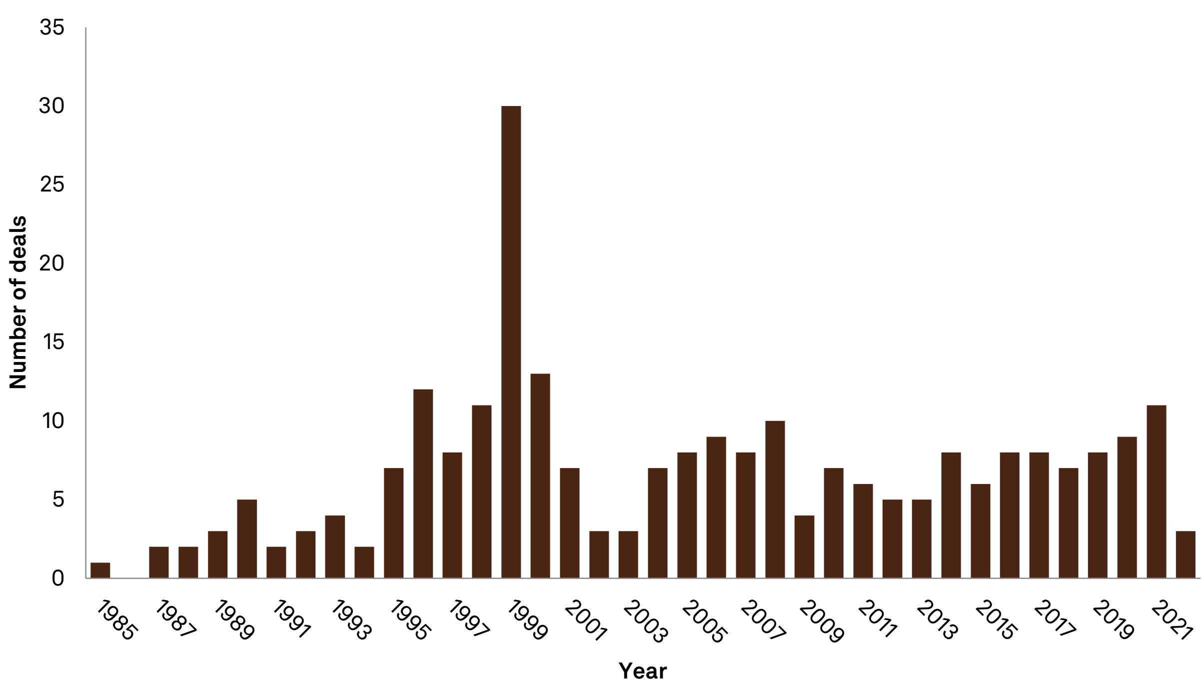
Corporate governance — The term corporate governance generally refers to a commission's ability to intervene in a utility's financial decision-making process through required preapproval of all securities issuances, limitations on leverage in utility capital structures, dividend payout limitations, ring fencing protocols and authority over mergers. Corporate governance may also include oversight of affiliate transactions.

In general, RRA views a modest level of corporate governance provisions to be the norm, and in some circumstances, these provisions, such as ring fencing, have protected utility investors as well as ratepayers. However, a degree of oversight that would allow the commission to "micromanage" the utility's operations and limit the company's financial flexibility would be viewed as restrictive.

In recent years, RRA has observed an increasing emphasis on environmental, social and governance issues, supplier and workforce diversity and social justice issues. In many instances, these policies are part and parcel of the ongoing energy transition. At this time, RRA takes no view on whether or not policymakers/regulators should adopt these practices, but where specific policies or targets are implemented, RRA evaluates the manner in which costs associated with compliance are recovered.

Merger and acquisition activity — During the 1980s and early 1990s, there was not a lot of merger and acquisition activity in the sector. The years 1998 through 2000 saw a spike in activity, a lot of which centered around electric industry restructuring. After that, activity moderated but has remained fairly steady.

Utility M&A transactions announced, 1985 - 2022 YTD



Data compiled as of May 27, 2022.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

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Though merger and acquisition activity slowed during the first half of 2020 due to the COVID-19 pandemic, the pace picked up in the second half, with ultimately nine mergers announced, with an aggregate transaction value of about $34 billion.

In 2021, 11 deals were announced that RRA followed, with an aggregate transaction value of roughly $56 billion. Thus far in 2022, RRA is following two announced deals, with a combined transaction value of a little over $8 billion.

Aside from the involved entities' boards of directors and shareholders, deals involving regulated utilities must pass muster with some, or all, of a variety of federal and state regulatory bodies. The states generally look at the day-to-day issues, such as the impact on rates, safety and reliability.

Looking more closely at the role of state regulators, 50 of the 53 non-federal jurisdictions that RRA follows have some type of review authority over proposed mergers. In Indiana and Florida, preapproval by state regulators is not required before a transaction can proceed. In Texas, approval by the Texas PUC is required before a transaction involving an electric utility can take place, but Texas RRC approval is not required for a transaction involving a gas LDC.

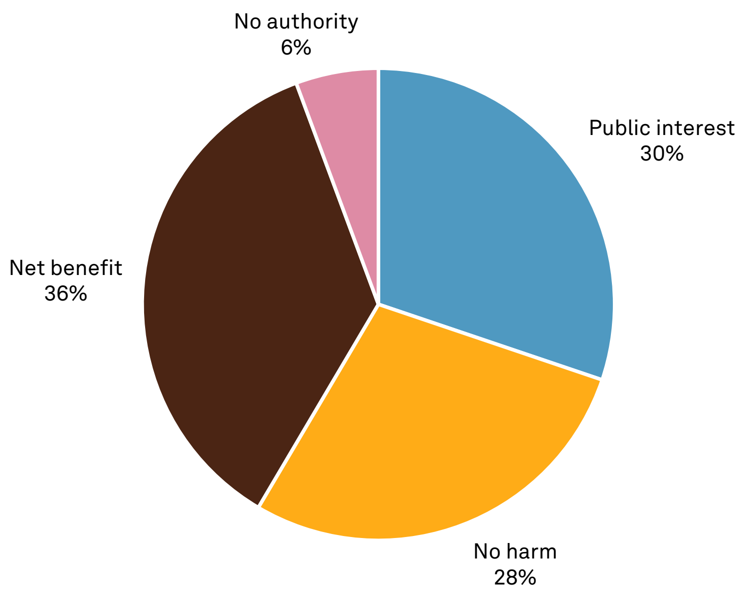
In evaluating a commission's stance on mergers, RRA looks at several broad issues, such as whether there is a statutory time frame for consideration of a transaction and how long a commission generally takes to review a deal.

For the 50 jurisdictions where commission preapproval is required, the review process and standards vary widely. In 20 of the jurisdictions, the commission must complete a merger review within a prescribed period, but in the remaining jurisdictions, there is no timeline for their merger reviews, which means a commission could effectively "pocket veto" a transaction by delaying a decision until the merger agreement between the applicants expires or until pursuing the transaction is no longer feasible.

The definition of what constitutes a transaction that is subject to review can vary widely and may include sales of individual assets or a marginal minority interest as well as larger transactions where a controlling interest or the whole company is changing hands. State law often lacks specificity with respect to what constitutes a transaction that is subject to regulatory review.

In cases where the state commission has authority over mergers, RRA reviews the type of approval standard that is contained in state law and/or has been applied by in specific situations.

State commission merger review standards



Data compiled May 27, 2022.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

For discussion purposes, RRA groups the statutory standards into three general buckets: public interest, which is generally thought to be the least restrictive; no net ratepayer harm, which is somewhat more restrictive; and net ratepayer benefit, which is the most restrictive.

In many instances, regulators have broad discretion to interpret what the statutes may mean by these terms. So, the standard of review is often more readily apparent by looking at how prior transactions were addressed than by reading the statutory language — one commission's public interest might be another's net ratepayer benefit.

In addition, RRA considers whether a settlement was reached among the parties and, if so, whether the commission honored that settlement or required additional commitments. RRA also examines how politicized the process was: Did the governor, or in the District of Columbia the mayor, play a role? Did the transaction garner a lot of local media attention in the affected jurisdiction?

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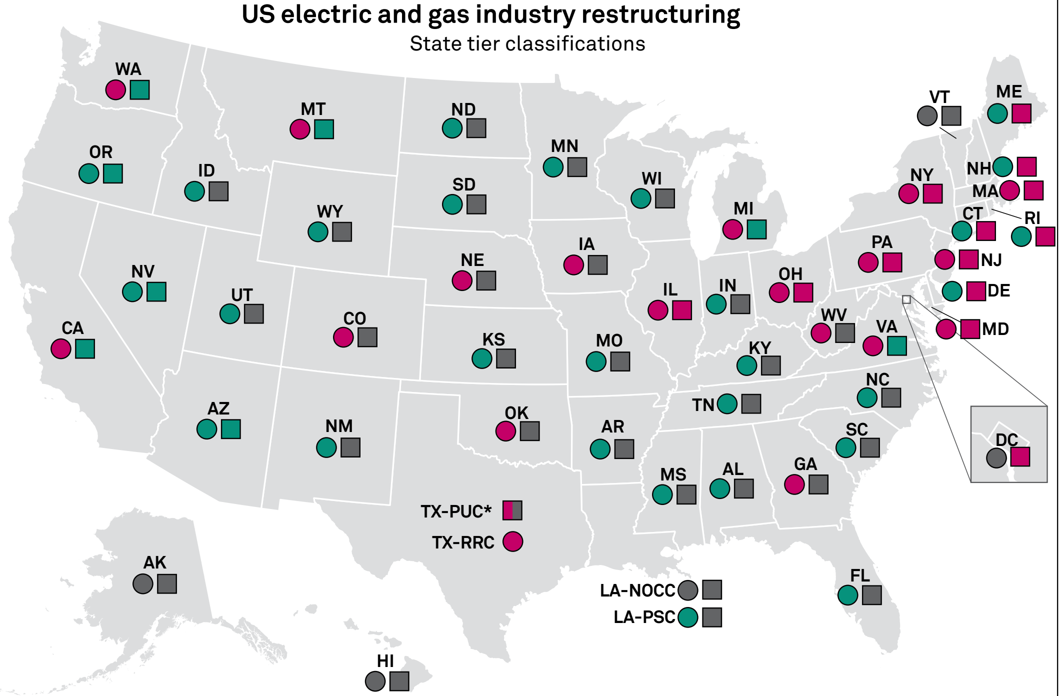
More narrowly, RRA reviews the conditions placed on the commission's approval of these transactions, including: whether the company will be permitted to retain a portion of any merger-related cost savings; if guaranteed rate reductions or credits are required that are or are not directly related to merger savings; whether certain assets were required to be divested; the type of local control and workforce commitments required; whether there are requirements for certain types of investment to further the state's public policy goals that may or may not be consistent with the companies' business models and if the related costs will be recoverable from ratepayers; and whether the commission placed stringent limitations on capital structure and/or dividend policy or composition of the board of directors.

Electric regulatory reform/industry restructuring — Electric industry restructuring refers to the implementation of a framework under which some or all retail customers have the opportunity to obtain their generation service from a competitive supplier of their choice. In a movement that began in the mid-1990s, about 20 jurisdictions have implemented retail competition for all or a portion of the customers in the utilities' service territories. The last of the transition periods ended as recently as 2011, when restructuring-related rate freezes concluded for certain Pennsylvania utilities.

Once the transition periods were completed, RRA focused more on how standard-offer or default service is procured for customers who do not select an alternative provider and how much, if any, market-price risk the utility must absorb.

US electric and gas industry restructuring

State tier classifications



Gas tiers

Tier 1 — All customers are permitted to competitively procure their gas supply, irrespective of volumes.

Tier 2 — Select customers are permitted to competitively procure their gas supply, usually based on volume.

Tier 3 — All customers procure their gas supply from the utility under bundled rates.

Power tiers

Tier 1 — Power prices are competitively determined for all retail customers within the jurisdiction; both standard-offer-service and retail-access customers. Retail access is permitted for all customers.

Tier 2 — Retail access is permitted to at least some customers/customer classes. Competitively priced power is limited to retail access customers. Power prices for standard-offer-service customers remain regulated. For the most part, utilities remain vertically integrated.

Tier 3 — Power prices are fully regulated for all retail customers. All retail customers must purchase their power from the franchised utility. Utiities are vertically integrated.

As of May 27, 2022.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission
* One in the Electric Reliability Council of Texas territory; three outside of it.
Map credit: Joe Felizadio
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

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RRA classifies each of the regulatory jurisdictions into one of three tiers, based on their relative electric industry restructuring status.

Gas regulatory reform/industry restructuring — Retail competition for gas supply is more widespread than electric retail competition, and the transition was far less contentious, as the magnitude of potential stranded asset costs was much smaller. Large volume customers in most states can select their gas supply provider; the availability of gas customer choice is much more limited for small-volume customers. Like electric retail competition, RRA generally does not view a state's decision to implement retail competition for gas service as either positive or negative from an investor viewpoint. RRA primarily considers the manner in which stranded costs were addressed and how default-service obligation-related costs are recovered.

Securitization — As it pertains to utilities, securitization refers to the issuance of bonds backed by a specific existing revenue stream that has been "guaranteed" by regulators and/or state legislators.

Securitization generally requires a utility to assign an eligible regulatory asset and a designated revenue stream for that asset to a "bankruptcy remote" special-purpose entity or trust; in some instances, a state financing authority fulfills this role. The trust or financing authority in turn issues bonds that will be serviced by the transferred revenue stream. The proceeds from the bond issuance flow to the utility, and in many cases, are used to retire outstanding higher-cost debt and/or buy back common equity, thus lowering the company's weighted average cost of capital.

What is Securitization?
Refers to the issuance of bonds backed by a specific existing revenue stream that has been "guaranteed" by regulators and/or state legislators.
Generally requires a utility to assign the designated revenue stream to a "bankruptcy remote" special purpose entity, which in turn issues bonds that will be serviced by the transferred revenue stream.
The funds raised by the bond issuance flow to the utility.

While it is unclear if securitization requires legislation, a specific legislative mandate generally improves the rating accorded securitization bonds and lowers the associated cost of capital, given that a legislatively supported revenue stream may be more difficult to rescind than a stand-alone order of a state commission. In RRA's experience, no state commission has authorized securitization in the absence of enabling legislation.

Securitization is viewed as an attractive option because it allows regulators to minimize the customer rate impacts related to recovery of a particular utility asset. The carrying charge on the asset would be the lower interest rate applied to a highly rated, usually AAA, corporate bond rather than the utility's weighted-average cost of capital or even the interest rate on typical utility bonds, which are generally rated BBB and carry higher interest rates.

At the same time, securitization reduces the investment risk for the utility by providing the utility up front recovery of its investment in what are usually non-revenue-producing assets. The company can then redeploy those investment dollars elsewhere.

The energy industry's introduction to asset securitization occurred in the mid-1990s, when legislation was enacted in certain states enabling utilities to securitize mandated conservation investments.

In the late 1990s and early 2000s, several states that implemented retail competition for electric generation enacted legislation allowing securitization to be used for recovery of uneconomic generating or other physical assets, above-market-priced purchased power contracts, regulatory assets, nuclear decommissioning costs, etc., that had the potential to become unrecoverable, or stranded, in a fully competitive market for generation supply.

In recent years, changing industry dynamics have once again begun to raise concerns about the prospects of stranded costs, and in some cases, securitization is being used to address generation facilities that are retired prematurely.

Securitization has also been used as part of bankruptcy-related reorganization plans, to finance fuel/purchased power balances, distribution system improvements and demand-side management programs and recover extraordinary storm costs.

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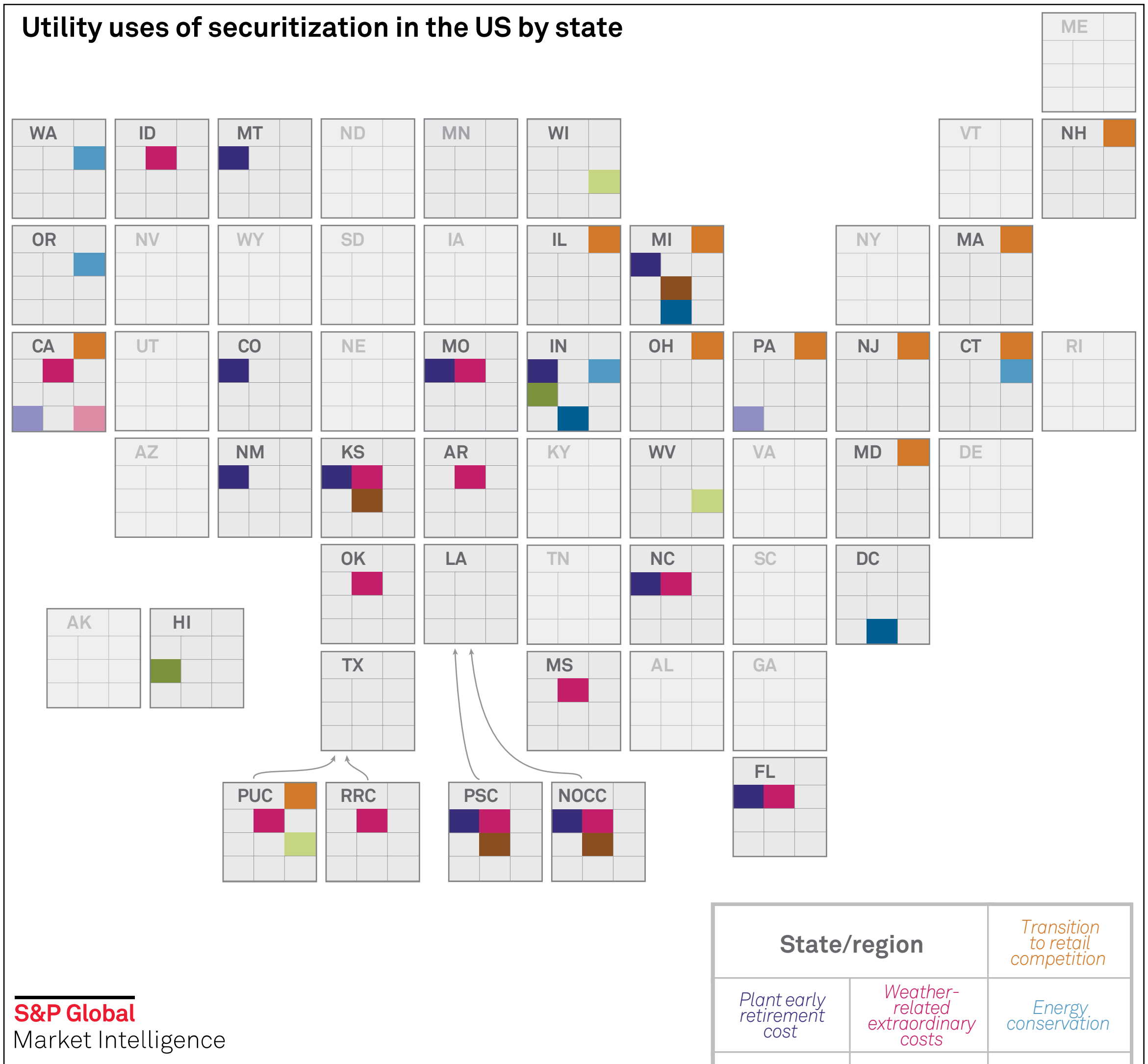
Utility uses of securitization in the US by state



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Data compiled May 27, 2022.
NOCC = New Orleans City Council; PSC = Public Service Commission
PUC = Public Utility Commission; RRC = Railroad Commission
Map credit: Joe Felizadio
Source: Regulatory Research Associates,
a group within S&P Global Commodity Insights

Adjustment clauses — Since the 1970s, adjustment clauses have been widely utilized to allow utilities to recover fuel and purchased power costs outside of base rate cases, as these costs are generally subject to a high degree of variability. In some instances, a baseline level is reflected in base rates, with only deviations from that amount addressed in the adjustment clause, whereas in others, the entire annual fuel/purchased power cost amount is reflected in the clause.

Over time, the types of costs recovered through these mechanisms were expanded in some jurisdictions to include items such as pension and healthcare costs, demand-side management program costs, FERC-approved regional transmission organization costs, new generation plant investment and transmission and distribution infrastructure spending.

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RRA generally views the use of these types of mechanisms as constructive, but also looks at the frequency at which the adjustments occur: whether there is a true-up mechanism; whether adjustments are forward-looking in nature where applicable; whether a cash return on construction work in progress is permitted; and whether there may be some ROE incentive for certain types of investment.

Another class of adjustment clauses, known as revenue decoupling mechanisms, allow utilities to adjust rates between rate cases to reflect fluctuations in revenues versus the level approved in the most recent base rate case due to a variety of factors.

Some of these factors, such as weather, are beyond a utility's control, and the mechanism can work both ways — they can allow the company to raise rates to recoup revenue losses associated with weather trends that reduce customer usage and can also require the company to reduce rates when weather trends cause usage to be higher than normal.

As energy efficiency initiatives have expanded, decoupling mechanisms have also been implemented to reduce the disincentive for utilities in pursuing energy conservation programs by making the utilities whole for reductions in sales volumes and revenues associated with customer participation in these programs.

Some of these mechanisms also allow the utility to adjust rates to reflect fluctuations in customer usage that are brought about by broader economic issues, such as demographic shifts, the migration of large commercial/industrial customers to other service areas, the shutdown of such businesses due to changes in their respective industries, recessions and, theoretically, crises such as the current COVID-19 pandemic.

RRA considers a decoupling mechanism that adjusts for all three of these factors to be a "full" decoupling mechanism and designates those that address only one or two of these factors as "partial" decoupling mechanisms.

Generally, an adjustment mechanism would be viewed as less constructive if there are provisions that limit the utility's ability to fully implement revenue requirement changes under certain circumstances, e.g., if the utility is earning more than its authorized return.

Another consideration is whether revenue requirement changes implemented under these mechanisms reflect historical changes in the relevant expenses or investment rather than forward-looking values.

Integrated resource planning — RRA generally considers the existence of a resource-planning process to be constructive from an investor viewpoint, as it may provide the utility at least some measure of protection from hindsight prudence reviews of its resource acquisition decisions. In some cases, the process may also provide for preapproval of the ratemaking parameters and/or a specific cost for a new facility. RRA views these types of provisions as constructive, as the utility can make more informed decisions as to whether it will proceed with a proposed project based on the expected level of support a utility proposal receives from regulators.

Renewable energy/emissions requirements — Goals for renewable energy deployment and emissions reductions have become increasingly intertwined in recent years and often need to be viewed in tandem.

As with retail competition, RRA does not take a stand as to whether the implementation of renewable portfolio standards, or RPS, or an emissions reduction mandate is positive or negative from an investor viewpoint. However, RRA considers whether there is a defined preapproval and/or cost-recovery mechanism for investments in projects designed to comply with these standards.

RRA also reviews if there is a mechanism, such as a rate increase cap, that limits the impact of the related public policy goals on customers. Such a mechanism could impede the utility's ability to recover program-related costs, pursue other investments and/or recover increased costs related to other facets of its business. RRA also looks at whether incentives, such as an enhanced ROE, are available for these types of projects.

The proliferation of renewables, particularly those that are customer-sited or distributed resources, and the related rise of battery storage and electric vehicles have raised questions regarding the traditional centralized industry framework and whether that framework needs to change, perhaps ushering in a second phase of electric industry restructuring. How these changes are implemented is something RRA considers in its rankings.

With respect to emissions, the threat of a federal carbon emissions standard for utilities and the spread of state-level initiatives have caused many companies to rethink legacy coal-fired generation, causing plants to be shut down earlier than anticipated. How the commissions address these "stranded costs" also poses a risk for investors and is factored into the rankings.

The zero-carbon movement has also caused utilities/states to reexamine investments in nuclear facilities and, in some cases, to develop programs designed to support the continued operation of those facilities even though they may not be economic from a competitive-market standpoint. How these issues are addressed is something that RRA also takes into account.

Rate structure — RRA looks at whether there are economic development or load-retention rate structures in place and, if so, how any associated revenue shortfall is recovered.

RRA also looks at whether there have been steps taken over recent years to reduce/eliminate interclass rate subsidies, i.e., to equalize rates of return across customer classes.

Fixed vs. variable costs

Fixed	Variable
Depreciation	Gas commodity
Delivery O&M	Electric commodity
Property taxes	Generation O&M
Return on investment	
Customer service	

Data compiled as of May 27, 2022.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

In addition, RRA considers whether the commission has adopted or moved toward a straight-fixed-variable rate design, under which a greater portion of a company's fixed costs are recovered through the fixed monthly customer charge, thus providing the utility greater certainty of recovering its fixed costs.

This is increasingly important in an environment where weather patterns are more volatile, organic growth is limited due to the economy and the proliferation of energy efficiency/conservation programs and large amounts of non-revenue-producing capital spending is required to upgrade and strengthen the grid.

In conjunction with the influx of renewables and distributed generation, the issue of how to compensate customer-owners for excess power they put back into the grid has become increasingly important and, in some instances, controversial. How these pricing arrangements, known as net metering, are structured can impact the ability of the utilities to recover their fixed distribution system costs and, by extension, their ability to earn their authorized returns.

Outlook

In RRA's view, the regulatory climates in the 53 jurisdictions under coverage has been relatively stable in recent months, resulting in no major changes to the relative level of investor risk in any individual jurisdiction.

RRA has identified seven jurisdictions where the outcome of ongoing proceedings or policy developments could cause a change in the future posture of the regulatory climate — California, the District of Columbia, Kentucky, Pennsylvania, South Carolina, Texas as it pertains to the electric utilities, and Virginia.

In addition, RRA has identified several ongoing issues that have broad nationwide implications, including the energy transition and the need to address related stranded costs, extreme weather events and the related impacts on costs and customer service and the end of COVID-19 pandemic.

New challenges have presented themselves in recent months, namely the conflict in the Ukraine, rising interest rates and inflation. The related overall uncertainty for the economy presents unique hurdles for this capital intensive, economically regulated industry. While these issues present challenges for all utilities, state regulators will play a pivotal role in determining the direction and magnitude of these impacts on the financial performance of the utilities that fall under their purview.

It is important to keep in mind that RRA's rankings are from an investor perspective and are intended to provide insight into the relative risk associated with owning the securities of the jurisdictions in question. They are not an assessment of whether regulators are "doing a good job." In addition, the rankings look at not only the commission's actions but those taken by the jurisdiction's legislature, courts and chief executive, as well as the various stakeholders that intervene in the regulatory process.

Further Reading

Law judge proposes lesser wildfire cost recovery for Southern California Edison
Safety, reliability, energy transition driving SDG&E's general rate request
Probation judge sees PG&E as 'continuing menace'; analysts see strong stock pick
Calif. grid still at elevated risk of blackout this summer, officials say
Calif. bill would speed power line burials, add strict 'performance metrics'
Calif. regulators delay vote on rooftop solar rule changes
Intervenors push back on WGL's DC gas rate proposal
Ky. PSC OKs AEP utility sale; conditions less onerous than intervenors sought
Pa. senators take another run at preventing RGGI entry as court cases progress
Va. legislative session ends with no action on RGGI, commission vacancy, budget
Utility Capital Expenditures Update — Energy and water utility capex plans on-track for record breaking 2022
US electric, gas ROE determinations in Q1'22 remain near all-time low mark
Major Rate Case Decisions January-March 2022
Road map: The energy sector braces for 2022 midterm elections
State lawmakers zero in on electric vehicles, nuclear generation during Q1'22
US regulators juggle stranded cost recovery, abatement strategies
Gas Ban Monitor: West Coast pushes new boundaries; pro-gas state bills stall
Utility Asset Securitization in the U.S.
Utility commissions begin to assess ratepayer effects of the Russian invasion
US governors call for energy independence as Russian invasion continues
US to boost LNG supplies to EU under joint game plan to phase out Russian gas
Energy security must include metal supply chain – US Energy Secretary
US governors place spotlight on EVs, clean energy in state addresses
Using DPA for US energy security is 'strong medicine' worthy of caution – expert
US steps up effort to track down Russian officers behind cyberattacks
New critical infrastructure malware is unlike anything cyber experts have seen
The Commissions
The rate case process: a conduit to enlightenment
Rate base: How would you rate your knowledge of this utility industry fundamental?

For detailed information about each jurisdiction's policies and regulatory ranking, visit the S&P Capital IQ Pro Commissions page.

For a full listing of past and pending rate cases, rate case statistics and upcoming events, visit the S&P Capital IQ Pro Energy Research Home Page.

For a complete, searchable listing of RRA's in-depth research and analysis, please go to the S&P Capital IQ Pro Energy Research Library.

About Regulatory Research Associates

Regulatory Research Associates, a group within S&P Global Commodity Insights, is the leading authority on utility securities and regulation. Understanding the financial and strategic impact of federal and state regulation is a key to success in the energy business. For nearly 40 years, Regulatory Research Associates has been the leading provider of independent research, expert analysis, proprietary data and consultation on utility securities and regulation. S&P Global Commodity Insights produces content for distribution on S&P Capital IQ Pro.

VERIFICATION

The undersigned, Brian K. West, being duly sworn, deposes and says he is the Vice President, Regulatory & Finance for Kentucky Power Company, that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Brian K. West

Commonwealth of Kentucky	)	
	)	Case No. 2022-00283
County of Boyd	)	

Subscribed and sworn before me, a Notary Public, by Brian K. West this 9th day of September, 2022.

Scott E Bishop
Notary Public

SCOTT E. BISHOP
Notary Public
Commonwealth of Kentucky
Commission Number KYNP32110
My Commission Expires Jun 24, 2025

My Commission Expires June 24, 2025

Notary ID Number: KYNP 32110